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ANNEX IV

GRANT NO. DE-FG22-89BC14444

FINAL REPORT

RELATING TO FOSSIL ENERGY RESOURCE CHARACTERIZATION,
RESEARCH, TECHNOLOGY DEVELOPMENT,
AND TECHNOLOGY TRANSFER

between the

UNITED STATES DEPARTMENT OF ENERGY

and

THE STATE OF TEXAS

on

OIL RECOVERY ENHANCEMENT FROM FRACTURED,
LOW PERMEABILITY RESERVOIRS

submitted by

TEXAS A&M UNIVERSITY

Principal Investigator

S. W. Poston

Co-Investigators

R. R. Berg

M. M. Friedman

A. F. Gangi

C. H. Wu

December 1993

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MASTER

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**OIL RECOVERY ENHANCEMENT FROM
FRACTURED, LOW PERMEABILITY
RESERVOIRS**

Contract No. DE-FG07-89BC14444

**Texas A&M University
College Station, TX.**

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Government Award: \$675,000**

**Principal Investigator:
S. Poston**

**Project Manager
R. Lindsey
Bartlesville, Office**

Reporting Period: 05/01/89 - 09/31/92

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Abstract

Geological, geophysical and petroleum engineering aspects of oil recovery from low-permeability reservoirs have been studied over the past three years.

Significant advances ^{were} ~~are~~ made in using Formation Microscanner Surveys (FMS) data to extrapolate fracture orientation, abundance, and spacing from the outcrop to the subsurface. Highly fractured zones within the reservoir can be detected, thus the fracture stratigraphy defined.

Multi-component, vertical-seismic profile (VSP), shear wave data ^{were} ~~are~~ used to improve the detection of fractures. A balancing scheme ^{was} ~~is~~ developed to improve the geophysical detection of fractures based on balanced source magnitudes and geophone couplings.

Resistivity logs can be used to 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.

Theoretical studies and analysis of daily production data, from field case histories, have shown the utility of the Chen Type Curves to derive reservoir character from production test data. This information is ordinarily determined from transient pressure data.

Laboratory displacement as well as MRI and CT studies show that the carbonated water imbibition oil displacement process significantly accelerates and increases recovery from saturated, low-permeability core material. The created gas drive, combined with oil shrinkage significantly increased oil recovery. A cyclic-carbonated-water-imbibition process improves oil recovery.

A semi-analytical model (IMOD) and a 3-dimensional, 3-phase, dual-porosity, compositional simulator (COMABS) ^{were} ~~are~~ developed to describe the imbibition carbonated waterflood performance. IMOD model is capable of computing the oil recovery and saturation profiles for oil/water viscosity ratios other than one. COMABS is used to match the imbibition oil recoveries obtained from carbonated waterflood experiments conducted on chalk cores and extend its application for field conditions.

One field trial was attempted. Performance data to determine the volume of additional oil recovery from the imbibition process was not conclusive because of operational problems.

Work on this project produced a number of publications and presentations at technical meetings and symposia. Three conferences on the Austin Chalk featuring our research along with presentations from operators in the chalk play were held on Texas A&M University campus.

Text on
page 124
says 2
meetings

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1989 - 1992 Final Report

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

1.0 - Executive Summary

The results of the investigative efforts for this jointly funded DOE-State of Texas research project achieved during the 1989-1992 period may be summarized as follows:

Geological, geophysical and petroleum engineering aspects of oil recovery from low-permeability reservoirs have been studied over the past three years. While examples dealing with the Cretaceous Austin Chalk of Texas have been emphasized, the approaches and results as well as the questions evaluated are generic and applicable elsewhere.

Reservoir Characterization. Natural fractures in outcrops and in the subsurface (Pearsall and Giddings Fields) have been characterized with a view toward evaluating to what degree fracture orientations, spacings and connectivities measured at the outcrop correspond to those in the subsurface. Using the Formation MicroScanner surveys (FMS) it is found that ^{of} tectonic and regional fractures ~~of~~ (only one set) (striking NE-SW) occur in the subsurface in contrast to two or more sets on the outcrop and that distribution of fracture spacings in the subsurface is either identical to or approaches that ^{of} ~~on~~ the outcrop. Other data on the correlation of strength, resistivity and gamma ray logs suggest that highly fractured zones within the reservoir can be detected and thus the fracture stratigraphy defined. A generic approach for the exploration for naturally fractured reservoirs is offered based on field, rock deformation laboratory and log analyses.

Detection of fractures also was studied using multi-component, vertical-seismic profile (VSP), shear wave data. Analysis of a data set from the Lost Hills Field, Kern Co., California, ¹⁾ shows one set of fractures oriented approximately N45°E; ²⁾ indicates that nearly all the fractures are located above 3,600 ft.; ³⁾ identifies reasons for spread in fracture orientation data; and ⁴⁾ develops a scheme to improve the geophysical detection of fractures based on balanced source magnitudes and geophone couplings.

Correlations of common well logs and rock properties measured in cores with the geological, geochemical and production characteristics of the Austin Chalk ^{were} ~~are~~ studied to

improve the evaluation of new drilling prospects. Results from ^{the} study of logs and cores from 14 wells along the Austin Chalk producing trend and logs and production data from 50 wells in the Giddings Field, Burleson Co., Texas, indicate (a) the response of well logs can be related to both organic maturity and natural fractures; (b) resistivity logs can be used to identify zones of immature organic materials, the zone of storage where oil is generated but held in the matrix, and the zone of migration where oil is expelled from the matrix to the fracture network; (c) natural fractures can be detected by the response of density logs in combination with gamma-ray, resistivity and sonic logs; and (d) production-decline curves can be interpreted to allocate the amount of oil production to fractures or to the matrix -- a technique most useful in confirming the log criteria for natural fractures in a local area.

Development of the EOR Imbibition Process. Laboratory displacement as well as MRI and CT studies show that the carbonated water imbibition oil displacement process significantly accelerates and increases recovery from saturated, low-permeability core material when compared to that of a normal brine displacement process. The created gas drive, combined with oil shrinkage, obtained by the evolving CO₂ from solution when the system pressure is decreased below the carbonation pressure, significantly increased oil recovery. A study of oil recovery by the application of a cyclic-carbonated-water-imbibition process, followed by reduction of the pressure below the bubble point of the CO₂-water solution, indicates advantages in applying the method in a cyclic manner.

Mathematical Modeling of Imbibition Carbonated Waterfloods. Two models: a semi-analytical model (IMOD) and a 3-dimensional, 3-phase, dual-porosity, compositional simulator (COMABS) ^{were} ~~are~~ developed to describe the imbibition-carbonated-waterflood-oil-recovery performance in naturally-fractured reservoirs. The major achievement of our IMOD model is that it can determine the oil recovery and saturation profiles for oil to water viscosity ratios other than one. To eliminate certain inherent limitations of the semi-analytical model, COMABS is used to match the imbibition oil recoveries obtained from carbonated waterflood experiments conducted on chalk cores. Results indicate that both semi-analytical and numerical models provide detailed analyses of imbibition oil recovery behavior by carbonated waterflooding. Since the semi-analytical method predicts oil recoveries with relative ease, it can be used to screen the potential application of imbibition waterflooding prior to initiating a full-field-scale-numerical simulation.

only 2 listed in text.

Transfer of Technology. Work on this project has resulted in a number of publications and presentations at technical meetings and symposia. In addition, three conferences on the Austin Chalk featuring our research along with presentations from operators in the chalk play were held on campus. Each of these conferences were attended by approximately 160 people from at least 50 different companies.

Field Tests. One field trial was attempted. Performance data to determine the volume of additional oil recovery from the imbibition process was not conclusive because of operational problems.

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 are: ① locating fractures ② low permeability in matrix

1 • *Reservoir Description* - Commercial oil production is dependent on the wellbore encountering a significant number of essentially vertical 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.

2 • *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.

3 • *Mathematical Modeling* - A semi-analytical mathematical model, IMOD, was developed to solve the integro-differential equation describing the imbibition displacement of oil by water in a fracture sandwiched by two matrix blocks. The imbibition oil recovery from a matrix block was represented by a transfer function. A numerical iterative method was employed to determine oil and water saturation distributions in fracture and matrix systems. The Stehfest numerical Laplace inversion algorithm was incorporated into the model to obtain the solutions in real domain numerically. The method is able to determine the oil recovery and saturation profiles for oil to water viscosity ratios other than one.

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 as follows:

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 involved the development of better techniques for *Reservoir Description*, while Tasks 3 and 4 were concerned with the development of a new *Enhanced Oil Recovery* method. Task 5 was 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 3 - year project was divided into these 3 major subjects of interest.

3.0 - Discussion of Research

3.1 - Reservoir Characterization

TASK 1: INTERPRETATION AND PREDICTING NATURAL

3.1A FRACTURES

CHARACTERIZATION OF NATURALLY FRACTURED RESERVOIRS

by

M. Friedman, D. V. Wiltschko, Kevin P. Corbett, J. Hung,

D. E. McKiernan, O. Kwon, and V. L. French

Center for Tectonophysics

Texas A&M University

*See
Table of
Contents*

OBJECTIVES

Field, laboratory and subsurface studies of fractures in the Austin Chalk are used to develop a better model to predict fracture orientations, spacings, apertures and abundance at depth in this low-permeability carbonate reservoir. This information is correlated with core description and log analyses to determine with what confidence fracture data obtained from outcrops can be extrapolated to corresponding reservoirs at depth and thus permit prediction of fracture development in the subsurface with a view toward exploitation via horizontal drilling. These models also can be utilized by petroleum engineers in their studies of the effectiveness of the imbibition process, and their attempts to model mathematically the performance of the reservoir.

PERSONNEL

~~To date~~ ^{worked} Four professionals ~~have been~~ ^t working on this Task, namely: Drs. M. Friedman, D. V. Wiltschko, K. P. Corbett and Jim Hung. Drs. Friedman and Wiltschko have been serving as the Task leaders. Dr. Corbett was hired to lead the field effort during parts of July, August and September 1990, and subsequently is involved in the exploration for naturally fractured reservoirs, world-wide for Marathon Oil Co. Dr. Jih-hao Hung, earned his doctorate in Geology, Department of Geology, Texas A&M University, and is currently an Assistant Professor at the Inst. of Geophysics, National Central University.

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Taiwan. Desiree E. McKiernan is making a study of fractures in the subsurface for her MS thesis principally using data from Schlumberger's Formation MicroScanner (microresistivity) surveys provided by UPRC, EXXON, ORYX and ARCO. Ohmyoung Kwon, a PhD candidate in the Department of Geology, is responsible for certain experimental rock deformation studies reported herein., and Victoria L. French, a MS candidate at Baylor University and soon to become a Ph D student at TAMU, is responsible for the recently completed field study of fracture spacing versus bedding thickness in exposures of the lower Austin Chalk (Atco Member) at the Lehigh Quarry, Waco Texas.

very dated!

SUMMARY OF RESULTS:

1. Our initial effort in study of the Austin Chalk and the take-off point for the current project was the field and laboratory MS thesis of K. P. Corbett¹ dealing with the structural stratigraphy of the Austin Chalk. It was recognized that the most highly fractured members of the chalk were the strongest mechanically with strength increasing with decreasing porosity, decreasing grain size and decreasing clay content. All subsequent work done on this project has reinforced that view (Friedman and Wiltchko², 1992, see APPENDIX IV, herein) Most recently, we have cross-plotted rock strength with deep induction resistivity and found that strength also increases with increasing resistivity for certain percentages of oil saturation and gamma ray response (clay content). Accordingly those chalk layers with the greatest propensity to fracture (assuming differential stresses owing to structure are sufficient to equal the fracture strength of the rocks in the brittle regime) can be identified from normal logs.

?
Should be Appendix I

Reorder the appendices to reflect the order of reference in this document.

2. The orientation and abundance of fractures have been characterized in outcrops relative to four structural types (Corbett et al³, 1991a, see APPENDIX I herein). The sizes of the structures studied in outcrop and the width of the fracture "halo" for each structure are about comparable to those encountered in the subsurface according to conversation with many operators. Frequency distributions of fracture spacing were determined along 14 scanlines placed on vertical outcrops and from 6 detailed maps of horizontal rock panels made at scales of 1:12 to 1:48 (Corbett, et al⁴ 1991b, Wiltchko et al⁵ 1991, here in see APPENDIX II AND III, respectively). These distributions are negatively exponential and are available for comparison with similar data from the subsurface collected via Schlumberger's Formation MicroScanner (FMS) device (see item 3 below). In addition, the abundance data indicate that fractures along scanlines oriented normal to the local major

following

structural trend (e.g., normal to the strike of local major faults or fold axes) is at least twice as closely spaced as along lines oriented parallel to these strikes.

3. Examination of the six detailed maps of fractured rock panels (scales of 1:12 to 1:48) indicate that "Nelson's Law" holds in such outcrops. That is, that the longest fractures are the furthest apart and probably have the greatest aperture (permeability). ^{from} ~~at~~ several of the maps it is clear that the longest fractures show the strongest ordered orientation, that they are the first to form (oldest), and that their connectivity with other fractures is such that one need be concerned only with intersecting the long fractures to adequately produce the naturally fractured reservoir. Typically the reservoir performance might be modelled by a three-hierarchy fracture assemblage with (1) smallest fractures being highly curved, probably assigned the lowest permeability and providing most of the boundaries to intact matrix blocks, (2) an intermediate length reasonably ordered set of straighter fractures of intermediate permeability, and (3) long, well oriented master fractures of largest permeability into which drain fluids from the other fractures.

4. Recently completed ^{field studies?} field study of fracture spacing versus bedding thickness in exposures of the lower Austin Chalk (Atco Member) at the Lehigh Quarry, Waco Texas, ^{of study shows?} show that (1) for "regional" fractures there is a strong correlation ($R = 0.9$) between bed thickness and fracture spacing with the spacing being about equal to the bedding thickness. In marked contrast, there is no such relationship for tectonic fractures in the hangwall of a nearby listric normal fault. The brittle-behaving Atco chinks in this quarry are conspicuously separated by ductile shales/marls such that most of the fractures are bed-contained. This same stratigraphic architecture characterizes the producing horizons in the greater Giddings field 100 miles to the SE. (see Item 6, ^{following} ~~below~~). Since the shale/marl layers are conspicuous on gamma ray logs, it is possible to map the thickness of the intercalated brittle chalk layers, at least in the Giddings field. Accordingly, an average fracture spacing essentially equal to the bed thickness is a useful parameter if indeed this aspect of the fractures in outcrop is to be extrapolated to the subsurface.

5. The direct comparison of data on fracture orientation and abundance obtained from outcrops and those developed in the subsurface has become possible only recently with the advent of horizontal drilling and the development, by Schlumberger, of a microresistivity tool, known as the Formation MicroScanner (FMS). The FMS device records, accurately, differences in resistivity along the borehole wall such that fractures and bedding are readily

detected. The Schlumberger software for the analysis of FMS data permits one to determine the (1) strike and dip of the fractures and bedding, (2) depth at which fractures occur (from [1 and 2] fracture spacing can be calculated as well as bedding thickness), (3) apertures of the fractures, (4) borehole trajectory along its length, (5) fracture development relative to lithology as inferred from resistivity, (6) whether fractures terminate at lithologic boundaries, and (7) structure from bedding dip and strike, directly observed small faults, and from interpretation of fracture orientation and abundance.

Results from use of the FMS and the comparison between fracture data measured at the outcrop compared to that in the subsurface are detailed in the master's thesis ~~recently~~ completed by Ms. McKiernan (see Appendix V). From study of over 9,000 fractures in eight horizontal boreholes from the Pearsall and Giddings Fields, she concludes that (a) only one set of fractures striking NE-SW is identified in the Austin Chalk reservoir at depth, compared to several sets of fractures relating to local structure and orthogonal regional fractures developed in outcrop; (b) the NE-strike direction is consistent with both regional and local structural strike; (c) specifically the strikes of the NE-SW trending fractures at the outcrop and in the subsurface differ by at most 20°; (d) the distribution of fracture spacings in the subsurface agrees well with that at the surface, e.g., at the outcrop >50% of the fractures are spaced <10-cm apart, while along the horizontal boreholes at depth >40% of the fractures are spaced < 20- cm apart; and (e) the close spacing of the fractures in the subsurface indicate that tectonic fractures relative to NE trending local structures are superposed on regional fractures just as they are at the outcrop.

Schlumberger kindly lent us their software program, trained Dr. Friedman and Ms. McKiernan in the analysis of FMS data, and worked with us to obtain FMS surveys from their clients.

6. Mr. B. Ray Holifield, one of the "fathers" of the Austin Chalk play, particularly in the greater Giddings Field, has emphasized the importance to the successful design of borehole-drilling plans (i.e., vertical, slant, horizontal and combinations thereof) where fractures are contained in brittle chalk layers separated by relatively ductile shale or marls breaks. Where fracture- containment prevails ~~then~~ there is poor vertical communication of the fluids in the fractures and the Austin Chalk becomes segregated into a number of separated reservoirs, even in the fracture halos of fault zones.

Outcrops of Austin Chalk show that most fractures are contained within the brittle chalk layers when the shale/marl breaks are equal to or greater than 10-cm thick. However, there are exceptions to this generality and some fractures are observed to terminateⁱⁿ a bedding surface where the shale/marl is much thinner. Accordingly, an experimental study has been initiated to investigate^e the factors that control fracture containment. In brief, fracture containment within brittle layers is favored by relatively small effective normal stress across the layering (e.g., 10 MPa versus 50 MPa), by increasing thickness of the ductile member, by decreasing the displacement rate for fracture propagation and when Austin Chalk rather than Berea Sandstone is used as the brittle layer.

7. Indeed an underlying fundamental given in the extrapolation of structural data or any type of mechanical data from one locality to another (herein from the outcrop to the subsurface) is that the ambient physical conditions at the time of deformation should be the same. It is generally agreed that the current outcrop trend of the Austin Chalk has deformed by brittle fracture associated with the same stresses that produced faults and some folds. Depth of burial along this outcrop trend was never more than about 1 km. Thus the vertical component of the weight of the overburden was about 7 to 10 MPa. On the other hand, productive portions of the Austin Chalk may have been buried as much as 4 km. When fracturing occurred during burial and uplift and what the pore-fluid pressures might have been at that time are extremely important if the mechanical condition of the reservoir is to be predicted. Several lines of evidence are discussed herein that indicate fracturing either took place (a) very early in the burial history of the chalk when effective pressures were small because the overburden was thin, and/or (b) at greater depth but associated with the high pore pressures generated during hydrocarbon maturation such that low effective pressures obtained and fostered brittle behavior.

8. Finally, Friedman and Wiltschko⁴ (1992, see APPENDIX (IV), herein) present a generic approach to the exploration for naturally fractured reservoirs based on this study of the Austin Chalk. In this paper the authors integrate data and concepts dealing with (1) orientation of fractures in local structures, (2) fracture-spacing, length and connectivity in outcrop, (3) extrapolation of outcrop data to the subsurface, (4) factors that control fracture in rock and the structural (fracture) stratigraphy, and (5) inferences concerning oil maturation, migration and trap and seal formation.

PRODUCTIVITY AND TECHNOLOGY TRANSFER ACTIVITIES

Publications reporting progress on this project now include three papers, one field guidebook, and abstracts to two oral presentations (see Reference List, below). In addition, presentations on the Austin Chalk study have been made in (a) two major technology transfer symposia, held at Texas A&M University on June 3, and October 16, 1992, (b) at least 3 short courses on naturally fractured reservoirs sponsored by the AAPG and private companies, (c) at least 3 field trips to outcrops of the Austin Chalk sponsored by AAPG or private companies, (d) presentation of progress to a group of industrial associates, and (e) presentations to faculty and students at Stanford University, Texas A&M University and the University of Oklahoma. In addition, two papers will have been accepted for presentation one at the SPE/SP CIM sponsored symposium on "Recent Advances in Horizontal Well Applications, Calgary, March 20-23, and the other at the North American Rock Mechanics Symposium, Austin, Tx, June 1-3. Copies of our publications have been sent to numerous persons within the industry, who have made telephone inquiries concerning our work.

FINDINGS ~~AND~~

PROGRESS NOT REPORTED IN APPENDICES

Fracture bed-containment. Field observations focused on the vertical continuity of fractures in the Austin Chalk indicate that many fractures are contained within brittle chalk members when the latter are bounded by relatively ductile shales or marls that exceed 10-cm in thickness. This feature is well-exposed in the Lehigh Cement Quarry of the Lehigh Portland Cement Co., Waco Texas (Corbett et al⁴, 1991b) and is reported as the dominant style in the subsurface of the Giddings Field (Holifield⁶, 1992). The importance of fracture bed-containment to the plan 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. Thus along fault zones and away from them, there may be poor vertical continuity of fractures when shale or marl breaks are locally numerous and relatively thick.

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 from within relatively thin, isolated units. Such volumetric calculations lead to the conclusion that either there is some vertical connectivity or that horizontal connectivity occurs over surprisingly large distances parallel to the chalk layers.

Good Work!
but not needed in the final technical report

Delete or include in one section for the whole report.

See the Table of Contents comments

What factors promote bed-containment of the fractures? A series of laboratory experiments have been completed wherein fractures initiate in a brittle rock and propagate toward a "bedding plane" and a relatively ductile layer of bentonitic clay. Whether or not they cross the bedding or are contained within the brittle member (fracture-bed-containment) 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. *In brief, we have learned that fracture containment is enhanced by increasing thickness of the ductile layer, decreasing effective confining pressure, slower displacement and when Austin Chalk itself is used as the brittle layer instead of Berea Sandstone as originally used.*

In this presentation the focus is on the vertical continuity, or lack of same, afforded by fractures in the chalk. In his presentation at our first Symposium on the Austin Chalk trend, B Ray Holifield offered the observation that 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" (Holifield⁶, 1992, p. 2), that "rapid depletion is caused by a series of barriers to vertical drainage by shales" (IBID, p. 3), that "the cause of low reserves is that usually only one fault had been penetrated by the horizontal wellbore and that shales caused the thickness of the producing reservoir to be small" (IBID, p. 10), and that "evidence confirms that 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" (IBID, p. 10). To emphasize his point Mr. Holifield offered several cartoons (Figure 1, ~~herein~~) showing a variety of borehole plans in keeping with the concept that shale breaks foster fracture bed-containment.

While field observations tend to confirm the role of shale breaks in fostering fracture bed-containment, there are instances where fractures do tend to cross bedding planes and shale beds. Moreover, it might be possible to predict^{ed} with greater assurance the influence of the shale beds ^{if} ~~were~~ a better genetic understanding of the phenomenon ^{was} in hand. Accordingly, it is important to understand what factors generically control shale bed-containment.

A series of simple laboratory experiments were conducted utilizing apparatus in ~~our~~ ^{the} Center for Tectonophysics. As shown schematically in Figure 2, the specimen is a 5-cm diameter by 10-cm long right-circular cylinder consisting of two sub-cylinders of brittle rock (initially Berea sandstone and later Austin Chalk) either in contact with a ductile layer consisting of bentonitic clay or in contact with each other, i.e., no clay. The upper brittle

member contains a notch (2-mm wide) sawed partially through the piece that terminates in a finer notch (1-mm wide). 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 extension fracture so produced 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 (from zero to 15 mm), the effective confining pressure (10 and 50 MPa), the displacement rate for the propagation of the extension fracture (0.25mm/sec to 0.025mm/sec.), whether the clay was room-dry or water-wet (50:50 water to clay, by weight) and most recently, if Austin Chalk is used instead of the equally brittle Berea Sandstone. These parameters and the experimental results are listed in Table 1 and shown as an XY plot in Figure 3.

Examination of the results shows that fracture-bed-containment is favored by increasing thickness of the shale, low effective pressure, slower displacement rate and when chalk rather than sandstone is used as the brittle member.

The result that perhaps is of greatest predictive value is that fracture bed-containment is favored by low effective confining pressure. Indeed, extrapolation of fracture data from outcrop to Austin Chalk reservoirs in the subsurface is dependent upon the chalk at depth also having deformed brittly at low effective confining pressure. Since fractures in the outcrops of the chalk occurred at a maximum depth of burial of only 3,000 feet, the maximum vertical effective stress and assumed lithostatic condition (owing to the weight of the overburden minus a normal water pressure gradient) during fractures was only 1,500psi (10 MPa). Under these conditions the chalk obviously behaves brittly.

How might such low effective pressures occur in the chalk reservoirs at depth. Two scenarios are pertinent. 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, comparable to that along its current outcrop trend. Other operators agree there probably was an episode of early deformation (prior to Pecan Gap time), but that clearly 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 9000 ft to 13,000 ft, R. R. Berg, Personal Communication, 1992) during which time maturation of its indigenous hydrocarbon produced high formation (pore) pressures (Hinds and Berg, 1990). 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 low permeability shales. In either case high pore pressures would obtain thereby reducing the effective stresses and causing the chalk to be weak and brittle, to fault and fracture, and to have bed-contained fractures, in the main.

Accordingly, one would predict fracture containment at depth provided the stratigraphic architecture of the Austin was characterized by shale or marl intercalated between chalk layers.

Correlation of fracture strength and resistivity. One of the principal objectives of our work is to predict stratigraphic zones within a naturally fractured formation that contain disproportionately large abundances of fractures. In other words, to determine a "fracture stratigraphy" within a formal stratigraphy where the beds would have the greatest propensity to fracture assuming some tectonic loading condition obtained. Ideally, we would like to be able to make this prediction through use of 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. Toward this end we have learned that when structural position, porosity and effective pressure are held constant the strongest rocks in the section will be the most highly fractured. This has been verified by plots of fracture abundance against rock type and grain size in naturally deformed rocks (Sinclair⁷, 1980. and Johnson⁸, 1985) and by our own experimental work on the Austin Chalk (see Friedman and Wiltschko², 1992, Figure 11b, attached here as APPENDIX IV)

Recently we were able to correlate 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, with deep induction resistivity, oil saturation and gamma ray readings from the same wells. Both the log- and the strength-data are courtesy of the Exxon Corporation, U.S.A. These cross plots (Figures 4 and 5) were prepared by Dr. R. R. Berg, and his students, Dept. of Geology, Texas A&M University

According to Dr. Berg (Personal Communications, October 1992), "resistivity (R_{id}) of the Austin Chalk is influenced by variations in clay content and oil saturation. In addition, the gamma-ray response is also influenced by clay and oil saturation. These

effects are shown by graphs of resistivity as a function of strength with z-values of oil saturation and gamma readings. Two resistivity plots are shown for each z-value: (1) the resistivity at the sample depth, and (2) resistivity as a 5-ft running average for the sample depth. The running-average resistivity was used to eliminate possible errors in core and log depths.

"Resistivity shows a general increase with increasing strength and increasing oil saturation (Figure 4 a,b). The increase in resistivity is more regular ($R=0.81$) in the range of 5 to 30 ohm.m for samples that contain oil saturation of zero to 14%. Anomalous values of resistivity are those of higher oil saturations 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 and are needed to confirm the apparent relationship.

"The same general increase in resistivity with strength is influenced by the gamma response (Figure 5 a,b). The increase in resistivity is more regular for samples with low gamma readings in the range of 20 to 33 API units ($R=0.88$), with the exception of one point (52 API and low strength). Anomalous values of resistivity have higher gamma readings in the range of 36 to 87 API. The single high resistivity point (65-ohm.m) has no gamma log at the bottom-hole level of the sample.

"The anomalous resistivity values in each case are probably due to increased oil saturation. The gamma response is normally expected to reflect clay content, increasing gamma with increasing clay. However, the anomalous resistivities correspond to increased oil saturations. It is likely that radioisotopes of heavy metallic elements (Ra, U, Th) 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, i.e., for samples with nearly constant oil saturations].

"Some samples may represent high clay content. For example the sample with low resistivity and high gamma value (52 API) also has the lowest strength of about 165 MPa

(Figures 5 and 6). This sample probably contains a high clay content because of its low resistivity [and therefore has a slow strength]"

Correlation of bed-thickness and fracture spacing. Exposures of the Austin Chalk in the Lehigh Quarry, Waco, are marked by distinct intercalations of shales/marls and brittle chalk layers. As such 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 are particularly important between these two locations. We already know from reports of B. Ray Holifield⁶ (1992) that in the Giddings Field the shale/marl breaks tend to foster bed-containment on the fractures. The question remains, however, how the fractures are spaced.

Ms. Victoria L. French mapped all fractures along exposed vertical face (cross-section) 85-m long and oriented N82W. 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 except as noted below.

A plot of fracture spacing versus bedding thickness for the regional fractures shows a strong trend (R [correlation coefficient] = 0.9) with the fracture spacing about equal to the bedding thickness (Figure 6a). A similar plot for the tectonic fractures (Figure 6b) shows no consistent trend. The actual average spacing for both types of fractures varies from 25 cm to nearly 60 cm. The fact that the regional fractures show a consistent spacing versus bedding thickness and the tectonic ones do not is consistent with similar measurements made elsewhere (Nelson⁹, 1985). The generality that for the Austin Chalk the fracture spacing is about equal to the bedding thickness is a useful one in that bed thickness can readily be determined from gamma ray logs.

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

Nelson's law. Nelson⁹ (1985) makes the point that in outcrops that display a mix of fracture sizes fracture length (a), fracture width (aperture) (b), and fracture spacing vary together with the scale of the fracture. For example, in outcrops with fractures of different length (a), the longer fractures are the widest (b) and are the farthest apart (d). This "law" is supported by predictions made from linear elastic fracture mechanics (e.g., see Pollard and Aydin¹⁰, 1988) i.e., (1) stress concentrations at crack tips are dependent in part on (a) and (b); (2) long fractures "shield" adjacent smaller ones and have a higher propagation energy such that their propagation is favored; and (3) when a number of parallel cracks propagate the length of the central crack tends to arrest the more distal fractures such that as more and more distal fractures are eliminated an increasing 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 Corbett and Hung as part of this effort, show both clear-cut examples of this "law" and also cases where the phenomenon is not easily appreciated (Figures 7 - 12). Where the "law" does hold it is clear that the longest fractures are the first to occur (i.e., are the oldest) and through intersections with shorter and more curved fractures the longer ones serve as the major element in what is often a three-fold fracture-drainage network. In such cases a horizontal wellbore penetrating these long "master" fractures will drain fluids from nearly the entire array of fractures.

SUMMARY AND CONCLUSIONS.

Through support provided by this DOE contract and matching funds from the University, primarily through its Center for Energy and Mineral Resources (CEMR) and Department of Geology, significant advances that been made by (a) characterizing the orientation, spacing and connectivity of fractures at a number of outcrops of Austin Chalk from Del Rio to Dallas, Texas, (b) determining the geometric and genetic relationships between fractures and structures in outcrop such as folds, listric faults, drape folds over faults, and grabens, (c) establishing the capability to analyze Formation Microscanner data (FMS) through the cooperation of Schlumberger and its clients, (d) extrapolating fracture orientation and abundance (spacing) from outcrop with those parameters in the subsurface in one well from the Giddings Field through use of FMS, with the results that fracture patterns seem simpler and less diffuse in the subsurface in contrast to those at the outcrop and that the frequency distribution of fracture spacing approaches or is the same in the

subsurface as in outcrop, (e) using conventional logs, particularly resistivity to infer indirectly rock strength and rock propensity to fracture, (f) establishing experimentally and through field observations that the strongest rocks will be the most highly fractured when deformed in the brittle regime, (f) gaining generic insights, experimentally, into factors that control fracture-bed-containment in stratigraphic sequences characterized by alternating brittle and ductile rock layers such as the Austin Chalk at the Lehigh Quarry in Waco and in the subsurface in the Giddings area, and by (g) transmitting these data via a number of different types of vehicles for technology transfer

On the other hand, the study is far from satisfactory completion. Needed are more (1) FMS analyses from additional boreholes to work on the outcrop-extrapolation problem, including not just geometry and spacing, but data on fracture aperture and fracture abundance versus resistivity, (2) correlations of resistivity with fracture abundance, (3) field work, particularly on fracture-bed-containment and the control of bedding thickness on fracture spacing in the Austin Chalk, and (4) work on integrating all data with a view toward developing a detailed fracture stratigraphy for the Austin Chalk. We hope to complete this work during 1994 with continued support from the University's CEMR.

Table 1 - Experiments on Fracture Containment

EFFECTIVE P_c^* (MPa)	CLAY THICKNESS (mm)	COMMENT ON RESULTS
Displacement rate: 10^{-3} in/sec: Berea Sandstone***		
10	0.0	fracture propagates across interface
50	0.0	ditto
50 (wet clay)**	5.0	fracture contained
50 (wet clay)**	5.0	fracture contained
10	5.1	fracture contained
10	10.9	fracture contained
50	3.8	fracture propagates across interface
50	6.8	fracture contained
50	10.0	fracture contained
50	10.0	fracture contained
50	10.6	fracture propagates across interface
50	15.2	fracture contained
Austin Chalk***		
10 (weak chalk)	9.5	fracture contained
50 (weak chalk)	9.2	fracture contained
50 (strong chalk)	9.5	fracture contained
50 (strong chalk)	9.8	fracture contained
Displacement rate: 10^{-2} in/sec Berea Sandstone		
10	10.5	fracture propagates across interface
10	10.6	ditto
10	14.7	fracture contained

* P_c , the confining pressure, also is the magnitude of the normal stress across the interface.

**Wet clay is 50:50, H₂O to bentonitic clay, by weight.

***The Austin Chalk and Berea Sandstone at these low effective confining pressures are equally brittle, however at $P_c = 10$ MPa, the Berea ss exhibits an ultimate strength of 125 MPa while the two chalks have ultimate strengths of 170 and 50 MPa, respectively.

The Mohr envelope for the Berea ss is $\tau = 20 \text{ (MPa)} + .55\sigma_n$ (Handin et al, 1963); that for the chalk averages $\tau = 9 \text{ (MPa)} + .64\sigma_n$ (Corbett et al, 1987).

Figure 1. Schematic illustration of bed-contained fractures in the Austin Chalk section at the Giddings Field (B. Ray Holifield, 1992). Fractures contained within brittle layers bounded by shale/marl breaks causes poor vertical continuity of fractures and the liquids they contain. This in turn dictates plan for borehole trajectory.

Figure 2. Schematic drawing of specimen configuration for study of factors that control fracture-bed-containment.

Figure 3. Influence of factors that control whether fractures are contained within brittle layers or propagate from brittle layers across ductile ones. Plotted is the thickness of the ductile layer (wet or dry layer of bentonitic clay) against the effective confining pressure (which also is the normal stress across the brittle/ductile layer boundaries; see experimental design, Figure). Open and solid circles indicate conditions for which fracture is contained within brittle layer (Berea sandstone and Austin chalk, respectively) with tests run at a displacement rate of 10^{-3} in/sec. Crosses indicate conditions for which fractures propagate across the ductile layer, also at 10^{-3} in/sec. Circles and crosses within () were run at 10^{-2} in/sec. Circles within < > were run with wet clay (1:1, water to clay by weight) at 10^{-3} in/sec. The wet tests were undrained, accordingly, the effective pressure probably was less than the nominal effective pressure of 50 MPa, hence the arrow. The numbers 2 and 3 before data points indicate that those many tests were made at those conditions to test reproducibility.

Figure 4.. Plots of deep induction resistivity against ultimate strength at 17 MPa confining pressure show the percentages of oil saturation for each sample as z-values. Ordinates for plots (a and b) are defined in text, but there is little difference between them. Clearly, there is a reasonably linear relationship between resistivity and strength for oil saturations between 0 and 14%.

Figure 5. Plots of deep induction resistivity against ultimate strength at 17 MPa confining pressure show Gamma values (API) for each sample as z-values. Ordinates for plots (a and b) are defined in text, but there is little difference between them. Again, resistivity correlates linearly with strength for gamma values, which reflect clay content, with narrow range of 20 to 33. Perhaps the weakest specimen is influenced by its high clay content.

"REGIONAL" FRACTURES

FROM HANGING WALL OF NORMAL FAULT

Figure 6. Plots of fracture spacing versus bed-thickness in the Austin Chalk (Atco member), Lehigh Quarry, Waco, Tx. The chalk section here is similar to that in the Giddings Field (160 km to the SE) and is characterized by brittle chalk layers from 25 to 65-cm thick intercalated with ductile shale/marls layers up to 20-cm thick. Measurements were made on a vertical exposure trending N82°E along which the bed-lengths vary from 33 to 63 m in (a) and 8 - 9 m in (b) with total fractures per layer varying from 57 to 186 in (a) and 23 to 29 in (b). (a) Plot for "regional fractures" genetically related to but not immediately adjacent to the Balcones grabens and cross-grabens. (b) Plot for "tectonic" fractures in hanging wall immediately adjacent to a normal fault. Correlation between bed thickness and fracture spacing is good for the regional fractures but poor for the tectonic ones.

Figure 7. Map of a portion of a fractured rock panel on a plunging gentle fold located SE of Del Rio, Texas. Fractures illustrate "Nelson's law" with the master set striking N55°E being the longest, exhibiting the largest spacing and probably having the greatest aperture. Note from the number of "T-intersections" that this set also is the oldest and has the greatest connectivity within the fracture network. It is oriented parallel to the axial plane of the fold. Mapping done by Drs. K. P. Corbett and J. Hung at a scale of 1:12 (see Willschko et al. 1991).

Figure 8. Map of a larger area at the same location as map in Figure 11. Again the N55° E fracture set fits "Nelson's Law".

Figure 9.. Map of a portion of the quarry floor at the Lehigh Quarry, Waco, Texas, also illustrates "Nelson's Law" in that the master fracture set striking $N10^{\circ}W$ is the longest, the furthest apart (largest spacing) and probably has the greatest aperture. Note from the number of "T-Intersections" that this set also is the oldest and has the greatest connectivity within the fracture network. The orthogonal fracture pattern is genetically related to the graben-in-graben structure and it is this set that largely contributes to the spacing data shown in Figure 10a. Mapping done by Drs. K. P. Corbett and J. Hung at a scale of 1:12 (see Wiltchko et al, 1991).

Figure 1Q Map of a portion of the quarry floor of the Old Alamo Cement Quarry, San Antonio. Mapping done by Drs. K. P. Corbett and J. Hung at a scale of 1:24 (see Willschko et al, 1991). A large percentage of the fractures are altered or filled and isolated from each other. Here the longest fractures (strike N10 -20°W) also are the closest spaced and are the best developed set of fractures in the panel. A less systematic second set strikes about N80°W and is composed primarily of fractures shorter than those of the NE set.

Figure 11. This map, also from the Old Alamo Quarry, San Antonio also shows a single very systematic set of fractures that here strike $N40^{\circ}E$. "Nelson's Law" is not testable in such an outcrop. Mapping done by Drs. K. P. Corbett and J. Hung at a scale of 1:24 (see Wiltchko et al, 1991).

Figure 12. Map of a portion of the quarry floor of the LaFarge Quarry, near Dallas, Texas. Mapping done by Drs. K. P. Corbett and J. Hung at a scale of 1:24 (see Willschko et al, 1991). In such a fracture array "Nelson's Law" is not readily apparent as the two main fracture sets (strikes: N45°E and N70°W) exhibit about the same length and spacing.

3.1.2 GEOPHYSICAL STUDIES

by

A. F. Gangi

*see Table of Contents comment
on authors.*

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 source component 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.

Shear waves (s-wave) may be split into components oriented in the 'fast' and 'slow' directions when propagating through an anisotropic medium. This splitting behavior is illustrated in Fig. 13. The horizontally polarized shear waves are seen to be travelling in the vertical direction in an elastic medium containing vertical fractures. The presence of the fractures will cause the shear waves whose motion is parallel to the faces of the fractures to possess a high speed. Shear waves whose motion are perpendicular to the fracture faces will have a lower speed. The fast and slow s-wave will be separated in time if the thickness of the fractured layer is sufficiently large.

Fig. 13 also shows that only the slow wave will be detected on a geophone oriented perpendicular to the fracture faces, or in the 'slow' direction. The fast waves may be detected by a geophone oriented parallel to the fracture faces, or in the 'fast' direction.

The 'fast' and 'slow' orientations and the vertical direction constitute the principal axes. The orientation of the principal axes can be determined by finding the direction for the sources and geophones where there is no motion on the fast or slow geophone when the source is oriented in the other direction. The geophone and source pairs must be maintained perpendicular to each other and each geophone must be oriented parallel to one of the source directions.

Fig. 13 - Shear-wave Splitting and Repolarization After Passing Through a Fractured Layer

There would be no motion on the geophone which is perpendicular to the horizontal source in an isotropic medium. The principal axes can have any orientation for an isotropic medium. An indication of an anisotropic medium is the detection of shear waves on geophones oriented perpendicular to the sources.

The data is usually read from the tapes and the traces are edited to eliminate bad traces. The data are then staked and the signals for the horizontal, in-line or cross-line and vertical, downward sources are generated by subtracting and adding the traces.

An example of the results of performing these operations for the horizontal components is shown in Fig. 14. The data traces begin at 1,600 ms where the direct s-waves begin. The p-waves occur at earlier times in the traces, but are not shown because only the s-waves are of interest when solving this particular problem. The s-wave forms are variable both in amplitude and time. These effects would be expected if the geophones are not oriented parallel and perpendicular to the source directions. The geophones can be oriented using the gyro data recorded for each geophone position.

The results obtained after 'gyro rotation' are shown in Fig. 15. Note the smooth variations of the first-arrival signals with depth. However, also note that the cross-diagonal components are not zero, as would be expected if the medium were isotropic. While some of the cross-diagonals may be caused by scattering from heterogeneities, the major part of these signals is derived by the anisotropy introduced by vertical fractures.

Hodograms were generated from these results. Fig. 16 is an example of some of the previously processed data. The hodograms are generated by the locus of the end of the vector obtained by the vector addition of the signals from the in-line and cross-line geophones. These hodograms would show rectilinear motion in the source direction only if the medium was isotropic. The motion for the cross-line source, in particular, are strongly non-rectilinear and neither hodogram is oriented in the direction of its source. This is a clear indication that anisotropy may exist.

Fig. 14 - Edited and Stacked Traces Before Gyro Rotation

Fig. 15 - Edited and Stacked Traces After Gyro Rotation

Fig. 16 - Hodograms Generated from Gyro Rotated Horizontal Components

Programs were written to:

- Stack the VSP data, reorient the signals received from the down-hole geophones, and edit and filter individual traces.
- Generate signals for in-line and cross-line sources.
- Rotate the source and geophone signals to the principal-axes orientations for anisotropic, fractured medium. Use the orientations of the principal axes to determine orientations of subsurface fractures.

The methods used to determine the directions of the fractures (i.e. the principal axes for the anisotropy) is to rotate the four horizontal components of the signals to the principal directions. The cross-diagonal terms will be zero, or at least minimized, when the signals have been properly rotated.

The recorded displacement field is a function of: 1) the in-line geophone component for the in-line source, 2) the cross-line component for the in-line source, 3) the in-line component for the cross-line source, and 4) the cross-line component for the cross-line

source. The (matrix) displacement field can be obtained after rotating both the source and receiver.

The fracture orientations were determined by maximizing the ratio of the energy windows in the rotated, 'in-line in-line', and 'in-line cross-line' components. The orientations are shown as a solid line in Fig. 17. The angles obtained by maximizing the energy ratio are shown as the dashed line. The asterisks on the depth axes indicate those depths for which the source location was changed. There is no strong correlation between the movement of the source truck and the variations in the determined fracture orientations. There are however, some small variations in the fracture orientation angle with depth. The measured fracture orientation is fairly constant with depth and is approximately N45°E. This is the inferred direction for the fracture planes.

Fig. 17 - Fracture Orientations Determined by Maximizing the Diagonal Energies

The ratio of the energy values in the 200 msec window in the inferred fast direction to that in the inferred slow direction are illustrated in Fig. 18. The energy ratio varies in fairly constant terms for all depths except at 5,000 and 7,100 ft where large deviations occur. These are also the depths for which there are large deviations in the fracture orientations observed in Fig. 17. The amplitudes for the in-line source were found to be small for the 5,000 ft depth compared to the other depths, while the signals at 7,100 ft for the in-line

source are noisier than seen in other traces. We concluded that the differences or imbalances in the in-line and cross-line sources for the 5,000 ft depth was the source of the large variability in the orientation at that depth.

The variation of the fracture orientation decreased substantially when the source strengths at 5,000 ft were equalized by increasing the signal level in both the in-line and cross-line components for the in-line source. Similar equalizations were performed for the traces corresponding to the other depths. The results for the fracture orientations after source balancing are shown in Fig. 19. Note, the variability in the fracture orientation is considerably decreased by this simple balancing procedure. The large variation persists for the 7,100 ft depth because of the noise in the in-line-source traces. The resulting 'average' fracture orientation is about N 45° E.

Fig. 18 - Ratio of Diagonal Energies as a Function of Depth

The time delay between the fast-fast components and the slow-slow component after source balancing for all depths is shown in Fig. 20. The average time delay is about 40 msec and remains relatively constant with depth. The time delay, is not unreasonable or unexpected since the sampling interval is 2 msec and that the frequency content in the signal peaks at about 10 Hz, with a variability of ± 4 msec.

Fig. 19 - Fracture Orientations Obtained after Source Balancing

Fig. 20 - Time Delay Between the Fast and Slow Waves

The odograms obtained for the rotated matrix of displacements at selected depths are shown in Fig. 21. The displacements are not only more rectilinear than those shown in Fig. 16, but they also are better aligned with the orientation of the sources. As in Fig. 16, the hodograms are quite similar with depth. However, the motions for the 'fast' source are predominantly on the 'fast' geophone, while the motions for the 'slow' source are predominantly on the 'slow' geophone. There still are relatively large components in the cross directions. Again, we believe these 'large' cross components are due to source and geophone imbalances.

Fig. 21 - Hodograms of the Principle Components When the Sources are Rotated at the Principal Axis

Choi and Gangi¹¹ 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 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 al¹² 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.¹³ Fig. 22 shows the normally distributed random numbers that were generated with this transformation.

Fig. 22 - The Normally Distributed Random Numbers

The cumulative distribution function for a normally distributed random variable equation discussed by Meyer¹⁴ was used. The generated random numbers were found to closely approximate a normal distribution.

The amplitude spectrum of the random number sequence is shown in Fig. 23 is seen to be quite flat for the full frequency range. The normalized auto-correlation of this noise sequence is seen in Fig. 24 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.

Fig. 23 - The Amplitude Spectrum 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. 25, the amplitude spectrum in Fig. 26 and the normalized autocorrelation is shown in Fig. 27.

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. 24 - The Normalized Autocorrelation of the Random Number

Fig. 25 - The Noise Sequence After Filtering

Fig. 26 - The Autocorrelation of the Random Number After Filtering

Fig. 27 - The Normalized 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 Gangi¹⁵. 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 28-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. 28-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

Fig. 28 - The Unbalanced VSP Data Set Without Noise

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. 29-a and 29-b. The off-diagonal traces of Fig. 29-a are identical, and those of Fig. 29-b are zero.

A noise sequence was added to give a S/N = 10 db to test the robustness of the balancing scheme. Fig. 30-a shows the VSP data set after adding the noise and Figure 30-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 31-a are readily detected, but the error energies on the off-diagonal traces of Figure 31-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. 29 - The VSP Data Set Without Noise But Balanced

Fig. 30 - An Unbalanced VSP Data Set with a $S/N = 10$ db

Figs. 31-a and 31-b show the VSP data sets after balancing. Amplitudes on the off-diagonal traces of Fig. 31-a appear balanced, and those of Fig. 31-b are very small.

Fig. 31 - The Balanced VSP Data Set with a $S/N = 10$ db

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.

Transfer of Technology - The following is a list of the presentations and publications pertaining to these subjects.

1. Choi, S., and Gangi, A.F.: "The Effect of Source Imbalances on the Determination of Fracture Orientation from VSP Data," presented at the 61 st Annual Meeting of the Soc. Exploration Geophysists, held Nov. 10-14, 1991, Houston.
2. Hudgens, E.: "Analysis of Vertical Resolution of Seismic Signals Associated with a Reservoir," M.S. Thesis, Texas A&M University (Dec. 1991)

Conclusions - The following conclusions may be derived from the conducted studies in this area.

- The orientation of the studied fractures was found to be approximately N 45° E.
- The bulk of the fractures are located above 3,600 ft and there is no significant fracturing below this depth.
- The lack of perfectly rectilinear motion for the hodograms from sources oriented along the principal axes is due to imbalances in the source strengths and the geophone couplings. These imbalances lead to significant deviations in the determination of the fracture orientations.
- A scheme to balance source magnitudes and geophone couplings has been developed.

TASK 2: RELATING RECOVERY TO WELL-LOG SIGNATURES

WELL LOG - PRODUCTIVITY RELATIONSHIPS

by

R. R. 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 productivity¹⁶. 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 abruptly¹⁷ and is accompanied by increasing amounts of saturated hydrocarbons and the C1 to C4 gases⁸ 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^{19,20}. Fig. 32 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.

Fig. 32 - Relating Water Saturation to Apparent Resistivity

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. 32 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 $S_w(R_t)$ relationship shown in Fig. 32 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 production²¹. 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_t 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_t 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. 33, 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. 33 - Cumulative Recovery as a Function of Apparent Resistivity

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, Hinds¹⁹; Hinds and Berg²⁰. Complete log suites are required for the interpretation. An example log is illustrated in Fig. 34. 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. 34 - Fractured Zones Detected by Well Log Response

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. 34. A fracture index, *FI* was devised to evaluate the intensity of fracturing.

$$FI = (h/z) \times 100$$

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. 33. 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. 33. 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. 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 Chen²². 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.

35. This well produced 129,000 bbl of oil during the first 72 months of production. All of the production can be attributed to fractures.

Fig. 35 - Production History - The Poehl Well

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. 36. 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. 35, 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.

Fig. 36 - Production History - The Marek Well

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 studies¹⁷. 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. 37A. These measurements define the threshold of generation, the storage zone, and the reservoir zone that are reflected in log response.

Fig. 37 - Geochemical Data from the Austin Chalk

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, Espitalie²³, and Forbes et al.²⁴. In other words, the *TR* values can be interpreted as the rate of oil generation with depth of burial. Refer to Fig. 37B. 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.

The final phase of the project investigated the role of solution seams in oil production. The Austin Chalk contains numerous, thin laminae which are the result of pressure solution. The laminae are relatively smooth, wavy or undulating seams that are generally horizontal or parallel to bedding and range in thickness from micrometers to millimeters. The smaller seams are few micrometers in length but larger seams extend entirely across the core face as very thin beds up to a centimeter or more in thickness. These seams have also been called "micro-fractures", and the late stage of low production rate has been attributed to movement of oil from the seams adjacent to tectonic fractures²⁵.

The laminae are termed solution seams because they lack the serrated boundaries of stylolites²⁶. The primary evidence for solution is the truncation of microfossils or rock fragments along the slightly irregular boundaries, Fig. 38. The seams are composed of insoluble materials, largely clay and amorphous kerogen, with small amounts of disseminated silica grains and pyrite. Thin stringers of bitumen are also present in many seams. The insoluble materials were concentrated along the seams during dissolution of

the rock matrix, and the bitumen was formed by transformation of the kerogen within the seams. The association of kerogen and bitumen suggests that solution seams were the principal sites of petroleum generation from organic material as well as the possible routes for primary migration of the bitumen.

Fig. 38 - Diagram of a solution seam in the Austin Chalk

The sequence of dissolution, generation, and migration may be visualized as follows. Dissolution of the rock matrix began along selected bedding planes during early compaction, and the clays and kerogen were concentrated in the solution seams. At the depth and temperature for oil generation, the kerogen began to transform to bitumen. Expansion of the bitumen opened microfractures filled with liquid, and the fractures propagated laterally and discharged their bitumen into nearby tectonic fractures.

The first oil generation probably took place along those seams which contained the highest content of kerogen. During microfracturing, the vertical extension stress caused compression of the adjacent rock and promoted further dissolution of the rock matrix along the seams. As oil was generated in another seam, compression of the first microfracture promoted further pressure solution and concentration of more kerogen in the first seam. Thus, the generation, microfracturing, and propagation took place alternately along different seams, and pressure solution accommodated the opening of microfractures. The process was repeated alternately in different seams until the supply of convertible kerogen was exhausted.

Oil remaining in microseams probably is that generated from laminae with small volumes of kerogen which were not sufficient to generate propagating microfractures. At a late stage of production, the pressure difference is large, microfractures are formed, and the oil is released to nearby tectonic fractures from which it can be produced at low rates.

The remaining problem concerns the conditions under which oil generation, microfracturing, and migration took place. So far, there has not been quantitative description of fracturing by oil generation such as that which probably occurred in the Austin Chalk.

Transfer of Technology - The following is a list of the presentations and publications pertaining to these subjects.

- 1 Schnerk, G.C., and Madeen, C.N.: "The Austin Chalk: Simulation of Horizontal Wells in a Heterogeneous Formation," paper SPE 20716 presented at the 65th Annual Technical Conference, 1990.
- 2 Buxton, T.M., and Sibley, D.F.: "Pressure Solution Features in a Shallow Buried Limestone," *Journal of Sedimentary Petrology*, (1981) 51, 19 - 26.
- 3 Behseresht, D.C., 1992, Correlation of Log Response to Production in the Austin Chalk: Texas A&M University, M. Sci. Thesis, 82p.

Conclusions - Several conclusions were reached regarding the area just described:

- 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.

FIELD APPLICATIONS OF HORIZONTAL WELL PRODUCTION DECLINE CURVE ANALYSIS

by

H. Y. Chen and S. W. Poston

A naturally fractured reservoir is composed of a medium comprised of fractures and matrix blocks. The properties associated with each sub-medium are quite different. The fracture-matrix geometry and extent and connectivity of the system is quite complex and definitely non-homogeneous. These features impose great difficulties in the modeling of a naturally fractured reservoir.

The first model describing fluid flow in naturally fractured reservoirs was presented by Barenblatt^{27,28}. The fracture and matrix sub-media were treated as continua. The fracture and matrix pressure fields are superimposed and are coupled by using a fluid interchange term. No specific fracture-matrix geometries are assumed since the model scale is relatively large. A large scale causes the fracture-matrix geometries to lose their identities after the overlapping-continuum assumption is imposed.

Two major difficulties arise when the Barenblatt overlapping-continuum concept is applied to real cases:

- It is difficult to visualize two pressures at each point.
- The permeability required to calculate the flow rate is difficult to define since the two pressure fields are overlapped and may or may not be operating independently or co-dependently.

Barenblatt simplified his dual-continuum theory by neglecting the storage capability of the fractures and the macroscopic permeability of the matrix blocks. Refs. 29 and 30 attempted to refine Barenblatt's dual-porosity theory by applying a fluid interchange term. Wijesinghe and Clham³⁰ derived a generalized theory to relax the steady-type interporosity flow assumed by Barenblatt. Chen et al.³¹ further simplified the theory and proposed an analytical, transient interporosity model. However, the inherent difficulties still remain since the main framework is based on Barenblatt's overlapping-continuum concept.

Another type of dual-porosity model requires an exact specification of fracture-matrix geometry^{32,33}. The problem essentially becomes not only tractable, but also, in most cases, solvable when the exact inner structure of a fractured medium is specified. This is especially true for the modeling of the fluid interchange term. The inner structure is assumed to be homogeneous. A fractured medium is represented by certain simple repetitive patterns such as layered, cubic, or spherical matrix blocks isolated by the

fractures. The major difficulty of such exact geometry models is that the assumed fracture-matrix geometry may not be consistent with field observations.

Both overlapping-continuum and exact fracture-matrix geometry models involve a fracture-matrix fluid interchange term. A common and logical issue is how to 'correctly' describe this term. Theoretically, the term is derived from a detailed reservoir description. In practice, however, the modeling of fluid interchange term is *the problem*.

Most research efforts concerning the modeling of naturally fractured reservoirs have more or less followed along the previously discussed lines. A completely different concept was explored in this study. The proposed concept has the following features:

- A single pressure field for each phase is assumed at each point.
- No explicit fracture-matrix geometry is assumed.
- A fluid interchange term is not required.

Model fundamentals - Darcy's law is always associated with a porous volume in a macroscopically and statistically correct nature. The Darcy velocity term actually is a fictitious velocity averaged over the cross sectional area of the porous medium. It is not a true velocity within the pore. This statement implies that the nature of the permeability associated with Darcy's law and the validity of Darcy's law depends on the defined pore volume.

Our approach is to use a modified form of Darcy's law, which takes into account the coexistence of fracture and matrix media with highly contrasting properties. As in the Barenblatt dual-continuum theory, the scale of the equation is sufficiently large to encompass two distinct types of media. Darcy's law would still be valid if only one type of media is considered. Therefore, we may say that this modified form of Darcy's law is derived from the original Darcy's law.

The approach is different from that used by Barenblatt. However, a casual examination of the solution presented by Barenblatt and wave type equations reveal certain similarities. This is probably due to the fact that a steady-type equation is used in developing our new modified Darcy's law and in Barenblatt's fluid interchange term. We also note that by neglecting the terms with order greater than two in any dual-continuum PDE results in a form similar to our outcome. The exact relationship, however, is immediately clear and is not identified at the present time.

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

1. Chen, H.Y., Poston, S.W., and Raghavan, R.: "The Well Response in a Naturally Fractured Reservoirs: Arbitrary Fracture Connectivity and Unsteady Fluid Transfer," paper SPE 20566 presented at the 1990 Annual Technical Conference and Exhibition, New Orleans, LA, Sept. 23-26.

Conclusions - An approach using a modified Darcy's law to model the naturally fractured reservoirs was proposed. The resulting governing PDE using the modified Darcy's law is a hyperbolic type equation. The development is highly heuristic. Justification from sound fundamental theory is still required. Also, the relationship between the proposed model and Barenblatt's must be identified.

Field Case History Studies - Dr. Poston and Dr. Chen

Prediction of fracture production from a typical Austin Chalk well presents a particular problem because of the extreme heterogeneity of the producing system. The permeability of the matrix rock is on the order of 0.01 to 0.0001 md, while the fracture permeabilities usually range from 10 to 100 times greater. The productivity of an individual Austin Chalk well depends to a very great extent on the intensity of the encountered fracture system, the extent of the natural fractures, and the permeability of matrix material. Estimation of remaining reserves and other reservoir characteristics is particularly difficult because of our inability to quantify the drainage character of the individual well. Additionally, most Austin Chalk wells are hydraulically fractured.

Well test and production records are usually the only information available for analyses. Therefore, decline curve analysis would be an obvious choice for predicting future production characteristics. The following section discusses the results of using type curves expressing dual fracture-matrix permeability flow to describe the drainage characteristics of Austin Chalk wells.

Fluid flow within this type of reservoir would be expected to be predominantly linear, not radial, since the major flow channels are fractures. Chen,³⁴ as a portion of the Annex IV research program developed production decline - type curves representing the expected flow characteristics from a dual fracture-matrix flow system. These type curves represent the expected producing characteristics for a reservoir possessing at least two different permeability fracture systems and a matrix block system. 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 into the micro-fracture system are represented by these curves.

The Geological Model - The work conducted by Dr. Friedman in the outcrop - subsurface portion of the Anenex IV study showed the regularity of the patterns and fracturing system in a typical Austin Chalk section. Micro-fractures connect the major (macro-) fractures. There is a pronounced lessening of the fracture intensity away from the center of the flexure. The geological model explains why horizontal drilling has been such a success in the Austin Chalk.

Concepts derived from the geological study may be summarized as follows:

- Major (macro-) fractures have a periodic spacing with a common orientation and have a permeability significantly greater than that of the minor fractures.
- There is a set of minor fractures roughly aligned normal to the major fractures, which connect the master fractures to each other.
- There is at least one other set of more subsidiary fractures which are in more or less random in nature.

Figs. 39 and 40 are idealized representations of a typical Austin Chalk fracture system.

Fig. 39 - Idealized Macro-, Micro- Fracture, and Matrix System - Plan View

Fig. 40 - Idealized Macro-, Micro- Fracture, and Matrix System - Cross Section

Mathematical Model Considerations - The geological discussion indicates the fracture network is comprised of a dominant array of near-vertical macro-fractures. The micro-fractures supply degree of interconnection varies between the macro-fractures.

A realistic mathematical model of the Austin Chalk must consider the spatially dependent fracture orientation, connectivity, distribution, and intensity. Specifically, there is a necessity to distinguish macro- from micro-fractures when describing the producing characteristics of an Austin Chalk well.

A single-fracture type model is coupled to a dual-porosity type model. The following assumptions concerning the expected fracture characteristics and producing mechanisms are used to simplify the mathematical treatment.

- The macro-fractures deplete under essentially steady state conditions and are connected to the micro-fractures.
- The micro-fractures are more or less connected and are considered as a continuous network. Flow from the micro-fractures may be at transient or pseudosteady state conditions, which subsequently feeds into the micro-fracture system. The matrix blocks are enclosed by the continuous fractures.

- Transient or pseudosteady state production from the matrix is fed into the micro-fractures. The matrix blocks act as supporting sources to feed the fractures with fluid.

The natural fracture network and matrix blocks are conceptualized as distinct, yet overlapping continua. The macroscopic flow pattern in the reservoir is presented by the flow in the natural fracture network superimposed by the flow system within the matrix blocks. Flow is from the fractured reservoirs, into the wellbore intercepted fracture, and then into the wellbore.

Fig. 41 Model Elements

Fig. 41 is an idealized comparison of the macro-and micro-fractures and the flow supporting matrix. The initial decline is controlled by flow from the macro-fracture system, while late time flow is principally a function of the matrix properties. Early time macro-fracture flow would be expected to be essentially level since the model defines this flow regime to be essentially steady state.

Type Curves - The type curves shown in Fig. 42 were constructed in a manner similar to the Fetkovich decline-type curves. A more extended discussion of the formulation of the type curves may be found in Refs. 31, 35, and 36. The dimensionless parameters

characterizing the dual fracture-matrix flow system are a storage-compressibility term (w) and a fracture extent term (γ):

The storage-compressibility term is defined as:

$$\omega = \frac{(\phi C_t)_f}{(\phi C_t)_f + (\phi C_t)_m} = \frac{(\phi C_t)_f}{(\phi C_t)_t}$$

The equation indicates that w is defined as the ratio of the storage-expansion value for the fracture system compared to that of the total system.

A high value of ω and homogeneous-reservoir-like production behavior would be an indication of poor fracture connectivity with relatively large matrix block sizes.

The fracture intensity term is defined as:

$$\gamma = (FI)^2 x_f^2 \frac{k_m}{k_f} \frac{(\phi C_t)_m}{(\phi C_t)_f} \beta_1 \beta_2 = \left(\frac{6y_e}{\pi l_c} \right)^2 \frac{k_m}{k_f} \frac{(\phi C_t)_m}{(\phi C_t)_f}$$

where FI denotes the "Fracture Intensity" in terms of "number of fractures per foot" and l_c is the characteristic length of the matrix block. β_1 and β_2 are normalizing factors and are defined in Ref. 31.

The unique feature for the dual fracture-matrix type curve shown in Fig. 42 is the extended production tail. This production extension is a direct consequence of the matrix contribution in the dual-porosity formulation. Naturally fractured reservoirs with the permeability of the matrix block being too small to permit significant fluid migration to the micro-fractures should display a pronounced "fall off" late in the life of the well.

Fig. 42 - Chen Type Curves

In conclusion and for a given production rate:

- a large value of γ tends to be associated with small values of w because fluid flow to the well is being maintained by the extended fracture system. Consequently,
- A small value of γ would have to be associated with large values of ω because the gas compressibility effect would have to be significant to maintain a comparable production rate.

The implication of the foregoing analysis is that qualitative interpretation of more than one phase producing simulation is realistic with these type curves even though the type-curves were generated with a single liquid solution.

Field Case Histories - Field case studies of production records from Austin Chalk, vertical and horizontal wells located in both the Parshall and Giddings Fields illustrate the utility of the new, dual fracture-matrix concept to determine the variation of reservoir character, the degree of connectivity of offsetting wells as well as the ability to generate area-wide "field" type curves.

The Bagget # 8 Vertical Well - IP 67 BOPD on 01/1979. Match characteristics $\omega = < 0.01$, $\gamma = 0.05$. The ω terms was the same as for two adjacent wells, 7 and 9. Well 7 had been completed one year previous to the # 7 well while the # 9 well had been completed at approximately the same time as the # 9 well. Oil production from the matrix is calculated to be 3,200 stb oil. Note, the significant difference in the levels between micro-fracture flow and matrix flow. All of the wells evaluated in this area showed this large difference in the two levels. There appears to be a significant difference between the micro-fracture and the matrix permeabilities. Fig. 43 presents the production curve match.

The Knesek A-1 Vertical Well - The well was drilled in late 1981. IP on 01/1981 was 67 BOPD. Match characteristics $\omega = < 0.01$, $\gamma = 0.05$. Note, the decline from micro-fracture flow to the matrix system appears to be essentially linear. This type of decline indicates the permeability of the micro-fracture and the matrix system are reasonably close to each other. Fig. 44 presents the production curve match.

Family of Curves - Three Horizontal wells: The A, B, and C wells were drilled and completed in 1990 and are adjacent to each other. The ω term was the same for the three wells, which indicates they are more than likely producing from the same fracture system.

Fig. 43 - Initialized Decline Curve - Bagget # 8 Well

Fig. 44 - Initialized Decline Curve - Knesek A-1 Well

Well A appears to be producing from a lesser fractured system than is observed by the other two wells even though its cumulative production is greater. Match points derived from Fig. 45 are listed in the following table:

Well	ω	γ	N_p
A	0.1	1	112,000
B	0.1	10	79,000
C	0.1	10	96,000

Fig. 45 - Family of Curves - Horizontal Wells

Reservoir Performance Plots

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 Curves³⁵⁻³⁹ 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/Dp .⁴⁰⁻⁴² Where, Dp is the difference between the flowing tubing head pressure at initial conditions minus the tubing head pressure at the time of interest.

$$Dp = (FTHP)_i - (FTHP)_t$$

These values of q/Dp vs t were plotted, analyzed and included in the following well analysis.

The Chen type curves³⁶⁻³⁹ 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.

The material balance is arranged in the form of a straight line for pseudosteady state flow. A Cartesian plot of Dp/q vs $Qcum/q$ will yield a straight line with slope, m .^{40,41}

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

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 $\log(Dp/q)$ vs $\log Qcum/q$ plot transfers the production plot to a pressure well testing format. Thus well testing analysis methods may be applied to the production data. $Qcum/q$

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 $\log(Dp/q)$ vs $\log Q_{cum}/q$ 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. 46 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. 46 - Marco #1 Production History

The $\log q$ vs t plot in Fig. 47 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. 48 is the resulting $\log Dp/q$ 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. 48 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 $g = 10^{-5}$ value.

Fig. 47 - Marco #1 Producing Segments

Fig. 48 - Marco #1 Log-Log Normalized Rate-Time Plot

The material balance arranged in the form of a straight line for the pseudosteady state condition results in Fig. 49 and 50. The normalized cartesian plot of Dp/q vs Q_{cum}/q shown in Fig. 37 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 $c_t = 1 \times 10^{-4}$ psi⁻¹.

Fig. 50 represents Fig. 49 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 γ indicates the production system is gradually extending outward into the fracture system. The unchanging ω 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 #2.

Fig. 49 - Marco #1 Well Test Plot - Cartesian System

Fig. 50 - Marco #1 Well Test Plot - Log-Log Plot

Table - 2 - The Marco #1 Well Correlation Values

	Fracture Intensity Term (γ)	Storage Compressibility Term (ω)	Comments
Initialize-1	10^{-2}	10^{-1}	
Initialize-2			Transient
Initialize-3	10^{-1}	10^{-1}	
Initialize-4	1	10^{-1}	

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.

Transfer of Technology - The following is a listing of the presentations and publications pertaining to these subjects.

1. Chen, H.Y., Raghavan, R., and Poston, S.W.: "An Application of the Product Solution Principal for Instantaneous Source and Green's Function in the Laplace Domain," *SPE Formation Evaluation* (June 1991)
2. Poston, S.W., Chen, H.Y., and Sandford, J.R.: "Fitting Type Curves to Austin Chalk Wells," paper SPE 21653. Presented at the 1991 Production Operations Symposium, Oklahoma City, OK.
3. Chen, H.Y., Poston, S.W., and Raghavan, R.: "Mathematical Development of Austin Chalk Type Curves," paper SPE 23527 submitted for publication, Dec. 1991; accepted for publication.
4. Poston, S. W., Chen, H.Y., and Aly, A.: "Applying a Geological Model to the Formulation of Production Decline Type Curves in the Austin Chalk," paper 3RC-74. Presented
5. Chen, H. Y., Ragahavan, R., and Poston, S. W., "The Well Response in a Naturally Fractured Reservoir: Arbitrary Fracture Connectivity and Unsteady Fluid Transfer," SPE 20566. Presented at the SPE Annual Technical Conference and Exhibition, Sept. 23-26, 1990, New Orleans, LA.
6. Poston, S.W., Chen, H.Y., and Sandford, J.R., "Fitting Type Curves to Austin Chalk Wells," SPE 21653. Presented at the 1991 Production Operations Symposium, Oklahoma City, OK.
7. Poston, S.W., Chen, H.Y., and Aly, A., "Applying a Geological Model to the Formulation of Production Decline Type Curves in the Austin Chalk," Paper 3RC-74. Presented at the Third International Reservoir Characterization Technical Conference, November 3-5, 1991, Tulsa, OK.
8. 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.
9. Poston, S.W., "Using Short Term - Pressure Transients to Determine Reserves and Reservoir Character," (Sept 4, 1992) Graduate seminar at University of Tulsa.
10. Aly, A.H., Poston, S.W., Chen, H.Y., and Barrufet, M., "Field Applications of Horizontal Well Production Decline Curve Analysis," Presented at the SPE Gulf Coast Area Meeting and Exhibition, Houston, TX, March 2-5, 1993.
11. Chen, H.Y., Raghavan, R., and Poston, S.W., "Average Reservoir Pressure Estimation of a Layered Commingled Reservoir," SPE 26460. To be presented at the 1993 SPE Fall Meeting, Houston, TX.

Conclusions - Type curves that represent flow equations describing a generalized geological model that approximates the expected fracture network system within the Austin Chalk were formulated. The utility of the new method to differentiate between individual well producing characteristics has been illustrated by comparing decline curves from two different areas in the Austin Chalk producing trend. Pronounced curvature between the micro-fracture flow region and the matrix flow region results in a qualitative estimate of the difference in permeability between the two flow regimes.

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 Dp . 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 Dp/q vs Q_{cum}/q will yield an approximate estimate of the matrix pore volume. Also, a $\log(Dp/q$ 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.

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3.2 - Development of a New Enhanced Oil Recovery Process

TASK 3: DEVELOPMENT OF THE EOR IMBIBITION PROCESS

THE WATER IMBIBITION PROCESS

by

J. M. Perez and S. W. Poston

The Enhanced Oil Recovery Concept - Conventional secondary methods cannot be applied to naturally fractured reservoirs because injected fluids channel through the fractures. Oil trapped in the matrix blocks is bypassed by the injected fluids. Water imbibition is a spontaneous mechanism that would cause oil located in the matrix to be naturally drawn out of the porous media by countercurrent flow of water from the fracture system. However, this process does not always occur and it might be very slow acting.

The proposed solution was to combine two agents: 1) water naturally imbibing into the rock, using it as carrier to bring a beneficial fluid in contact with indigenous oil, and 2) carbon dioxide, a fluid that has proven oil recovery enhancing characteristics.

The solution of CO_2 into the imbibing water would improve the oil recovery efficiency and production rate. The aim of the experimental effort was to develop a new EOR technique applicable to naturally fractured reservoirs, with low matrix permeability.

CO_2 Enhancing Qualities - 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 stock tank 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.

Oil production, its distribution inside carbonated rock samples, and the effects of introducing CO_2 into the imbibed water were studied using conventional laboratory displacement tests, Magnetic Resonance Imaging (*MRI*), and Computer Tomography (*CT*), analysis methods. The results of the imaging work provided more abundant and accurate data and facts regarding movement of fluids inside cores, compared to the conventional laboratory tests. *CT* and *MRI* imaging studies permitted cross sectional and longitudinal oil saturation profiles to be measured and monitored as a function of time.

Core Sample Preparation - All rock and reference samples used to study imbibition processes were drilled from the same piece of rock to assure similar characteristics. Carbonate as well as quartz sandstones were used in the laboratory experiments while limestone and dolomite cores were used during the imaging studies.

The sequence of laboratory work in the first phase was to cut, extract, and dry the cores and then determine their basic rock properties. The cores completely saturated with the wetting fluid were set in a core holder and flooded to a maximum oil saturation.

Carbonated water was formed by dissolving CO_2 in brine at some elevated pressure, usually 500 psi. The carbonated brine was usually 1% by wt. The CO_2 solubility data of Dodds et al.^{43,44} were used in these estimations.

Austin chalk crude oil was used to conduct the experiments. A high pressure core holder was set inside an oven to conduct the conventional laboratory displacement tests. A new fiber glass core holder was developed to be used in conjunction with *CT* and *NMR*. The core holder has dual fluid taps 3/4 inch apart, located at the inlet face of the core. The imbibing fluid is introduced through the lower inlet tap at a very slow rate. The brine sweeps across the core face to be produced through the upper tap. Oil expelled by the imbibition process is produced along with the circulated fluid. A back pressure regulator was used to maintain a 1,000 psi system pressure.

Laboratory Displacement Studies - Both limestone and sandstone core samples were studied. Sandstone permeability ranged from 107 to 389 md while the porosity averaged 20%. The permeability of the limestone cores averaged 9 md with an average porosity was 24%. Negligible recovery was observed from the sandstone cores.

The limestone cores showed increase in recovery and recovery rate when imbibed by carbonated water. Fig. 51 represents the results of the conventional imbibition experiments conducted on an 8.6 md limestone core. Imbibition displacement by the carbonated water method increased recovery by 26 % and permeability was increased to 10.3 md when compared to the normal water imbibition method. Additional recovery was induced when pressure was reduced below the bubble point. Dissolved CO_2 into the oil would swell it. A decrease in pressure below the carbonation pressure would force the CO_2 to evolve out of the water, creating a localized gas drive. At the same time, oil shrinkage would reduce the oil volume. Therefore, reducing the amount of oil left in place.

Fig. 51 - Comparing Recoveries from a Limestone Core - Constant Temperature

Fig. 52 compares the results of the imbibition experiments conducted for 48 hours at 70 °F and 110 °F temperature, using 4 % by weight carbonated brine. This concentration is equivalent to 130 cu ft of CO_2 gas dissolved in one barrel of 10,000 ppm brine at standard conditions.

An additional 34.2 % of *OOIP* was recovered at a 110 °F when compared with the recovery at 70 °F. The initiation of a reservoir blow down process yielded 12.7 % of *OOIP* at 70 °F and 16.6 % of *OOIP* at 110 °F. The solution gas-drive effect is more pronounced at higher temperatures.

Fig. 52 - Illustrating the Effect of Temperature on Oil Recovery from a Limestone Core

Fig. 53 illustrates the effect of CO_2 concentration in the imbibed water on ultimate recovery and recovery rate. An increase of 2.25 % to 4 % by wt in the concentration of dissolved CO_2 yielded an additional recovery of 50.9 % of *OOIP*. The solution gas drive effect after imbibing with the low CO_2 concentration brine resulted in a 6 % of *OOIP* increase in recovery, while the high CO_2 concentration brine resulted in an additional recovery of 14.6 % of *OOIP*. These experiments were conducted at 110 °F.

Fig. 53 - The Effect of CO_2 Concentration on Oil Recovery

Electron microscopic studies on the 9 md limestone indicated no discernable effect of matrix dissolution due to acidic nature of the carbonated brine.

MRI Studies - 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. 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 a maximum working pressure of 2,500 psi with a maximum confining pressure of 3,000 psi.

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, ϕS_o . Oil saturation changes can be calculated if porosity is assumed to remain constant.

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.

Proton profile images were used to map any oil saturation changes inside the rock samples. Deuterium Oxide, D_2O , was used in place of water to insure that only oil protons were observed. One and two dimensional images were recorded. 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 defined the number of oil protons present, which in turn reflected 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, ϕS_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.

MRI analyses permitted the changes in fluid saturations at any point within the rock sample to be visualized and quantified.^{45,46} The origin of the produced oil was detected by monitoring the oil saturation changes within specific locations within the core sample. Longitudinal images of the sample were primarily taken to observe oil saturation changes and movement along the main axis of the sample. A typical proton profile image is shown in Fig. 54. The number of protons or the oil saturation increases upward on the y axis. The figure is illustrative of a core sample flooded to a residual water saturation and ready for a water imbibition displacement test. The oil seen as the spike located at the core face (right hand side) will be displaced through the upper tap, initiating the imbibition process. 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 constant *NMR* signal from the reference samples was used to eliminate erroneous shifts in *NMR* responses taken at different times.⁴⁷

Fig. 54 - A Typical Proton Profile. Reference and Core Samples are Identified

The integral of the signal from the reference sample was used to normalize all the experimental data. The subtraction of profiles permitted the changes in oil saturation as a function of time to be quantified. A typical reconstructed set of oil saturation profiles observed during a normal brine imbibition flood is seen in Fig. 55.

Fig. 55 - Oil Saturation Changes as a Function of Time - Normal Brine Imbibition

The profiles appear to consist of a straight line trends from the core face to 0.5 in, with a straight line of lesser slope extending from 0.5 to 3 in. It is evident that the produced oil originates over the complete length of the sample.

Fig. 56 shows a cumulative oil production curve obtained by integrating the areas underneath each of the normalized proton profiles to determine displaced oil volumes. This method permits the amount of oil removed from the rock sample to be measured without the need to account for the volume of oil adhering to the rock surface. Introduction of errors caused by inaccurate calculation of fluid volumes by conventional methods is completely eliminated.

For the carbonated water case, the pressure was dropped below the bubble point after the oil production rate became insignificant. The pressure decrease permitted the dissolved CO_2 to evolve from liquid form. An artificial solution gas drive was created inside the sample. This localized gas drive expelled liquids out of the rock. A substantial decrease in oil saturation is observed when this phenomena is induced. Fig. 57 presents profiles before and after the induced process in a core sample.

Fig. 56 - Cumulative Oil Production During Imbibition Displacement of Pure Water

Subtraction of profiles presents a better description of the fluids movement inside the sample, see Fig. 58. On the other hand, a drop of the system pressure caused no effect when unadulterated water was being used. Fracture cleaning is also a beneficial effect. Oil trapped in the fracture or adhering to the rock surface was completely removed. This effect is evidence by the removal of the spike representing the trapped oil, in Fig. 57.

Oil saturation profiles do not exhibit the straight line trend shown for the case of pure water. A more accentuated decrease in oil saturation closer to the imbibing rock face was observed for the CO_2 cases. The drastic decrease in oil saturation in a region of the sample close to the imbibing face reveals that the carbonated water was not reaching the full length of the rock. The CO_2 is confined close to the core face.

Fig. 57 Oil Saturation Profile Illustrating the Effect of the Induced Solution Gas Drive

Fig. 58 - Illustrating the Combined Effect of a Carbonated Water - Induced Solution Gas Drive Depletion Study

CO_2 entrained in the imbibing water diffuses to the oil phase which is counter currently migrating to the core face, causing this phenomena. This is an obvious limiting factor for the process as well as all types of CO_2 enhanced recovery processes. This is the first time this phenomena has been noted.

CO_2 -enriched water imbibition and the localized gas drive created by the gas expansion were combined into a cyclic sequence to study the effect of repeated treatments on ultimate recovery and rate of recovery. This combination of imbibition and pressure pulsing produced a cyclic imbibition type of production. The new method combines several interesting advantages for increasing oil recovery. The sequence of events are as follows:

- The imbibition phenomena is used to carry the dissolved CO_2 into the core.
- The ability of CO_2 to preferentially diffuse from the water to the oil is used.
- The newly arrived CO_2 beneficially affects the oil properties which in turn increases the migrating abilities of the oil.
- A localized gas drive is created when the pore pressure is dropped below the bubble point pressure.

- A cyclic process keeps reintroducing the carbonated water into the reservoir, which to a great extent nullifies the problem of the imbibed CO_2 diffusing to the produced oil.

Fig. 59 compares oil saturation profiles at initial conditions and after 3 carbonated water imbibition-induced solution gas drive cycles. Note the ability of the cyclic process to move the region of low oil saturation further into the core.

Fig. 59 - Profiles Showing the Effect of the Cyclic Process

Oil Production from Homogeneous and Micro-Fractured Rock Samples.

Effects of dead-end fractures on oil recovery - 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.⁴⁸ Fig. 60 illustrate the relationships of large and small scale (open and dead end fractures), with a typical flow pattern. Water may easily flow and displace oil expelled from the matrix system along the open ended macro-fracture system shown in area A. However the producing mechanism that expells oil from the matrix into a dead end micro-fracture, had to be investigated. Relate to area B in Fig. 60.

Research conducted during the last years has shown that carbonated water flooding accelerates and increases oil production.⁴⁸ MRI analyses permitted the changes in fluid saturations at any point within the rock sample to be visualized and quantified.^{36,37} 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.⁴⁸ Fig. 50 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. 60 - 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 benefits of water carbonation have been previously discussed. These benefits 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.

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.

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 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. Again the *NMR* signal from the reference samples was used to eliminate erroneous shifts in *NMR* responses taken at different times.⁴⁷

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_2O or carbonated D_2O 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. 61 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 CO_2 in water is a function of pressure and temperature. The amount of CO_2 dissolved drastically decreases 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. 61 - Comparison of Recovery by Pure and Carbonated Water Imbibition

Fig. 61 shows oil recovery was increased nearly 5 fold with the inclusion of CO_2 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 Micro-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 propanant 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. 62 is an *NMR* image taken along and in the longitudinal fracture. Fig. 62A represents the core at the stage before imbibition was initiated and Fig. 62B represents the fluid distribution 1 min after water was introduced at the lefthand-most core face. The light colors generally represent irreducible 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.

Fig. 62 - NMR Images of the Micro-Fracture - The Pure Water Case

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.

Images 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, corresponding to the water invaded portion of the micro-fracture. There appeared to be little water imbibition-oil displacement effect elsewhere.

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. Fig. 63 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 recovery on the left hand side of the core to be greater than that seen on the right hand side of the core. More work needs to be done in this area.

Fig. 63 - 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. 64. 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.

Fig. 64 - 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.⁴⁸ These studies showed that carbonated water accentuated the imbibition-oil displacement process.

Fig. 65 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 fracture. This irregular shaped region is probably of a greater aperture. The water-oil saturation distribution throughout the fracture is readily observed.

Fig. 65 - NMR Images Measured Along the Micro-Fracture at Various Stages of Depletion

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 fracture.

Image C - The water is seen to have invaded a rather narrow and irregularly shaped band extending to the back and then upward in 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. 62. The presence of preferential channels even in defiance of gravity effects is obvious. The selection of these water flow channels could be function of aperture or changes in wettability. We are not sure at the present time. More work must be done in this area. This image was taken 15 minutes after the process had started.

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 CO_2 to evolve out of solution. The system was re-pressurized, using carbonated water, 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 CO_2 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. 66 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. The saturation changes observed prior to pressure depletion are the net effect of imbibition and oil swelling caused by CO_2 solution. When the swelled oil is depressured, it would shrink as CO_2 is liberated. Thus, the observed matrix oil saturation changes are partially due to shrinkage. Note the preferential change in saturation values on the right hand side of the profile.

Fig. 67 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 combination of gas drive and shrinkage effects decreased oil saturation to about 60%. The change in saturation profiles is much more uniform than those seen in Fig. 66. This observation emphasizes the concept of preferential flow channels. Fig. 68 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.

Matrix oil saturations 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 effects of removing oil adhering to the surface of the sample and evacuating oil inside the micro-fracture. Oil production caused by this effect was not considered when cumulative oil production curves were construction.

Fig. 66 - Oil Saturation Profiles Examined Perpendicular to the Micro-Fracture Plane
50.8 mm from the Core Face - Carbonated Water Test

Fig. 67 - Oil Saturation Profiles Examined Perpendicular to the Micro-fracture plane
12.8 mm from the Core Face - Carbonated Water Test

Fig. 68 - 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.

1. Perez, J., Poston, S.W., and Sharif, Q., "Carbonated Water Imbibition Flooding - An Enhanced Oil Recovery Process for Fractured Reservoirs," SPE 024164. Presented at the SPE/DOE Eighth Symposium on Enhanced Oil Recovery (April 22-24, 1992), Tulsa OK. ALSO Presented at the Mediterranean Petroleum Conference and Exposition, Jan 18-21, 1993, Tripoli, Libya.
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.
3. Poston, S.W., Perez, J., and Sharif, Q., "Carbonated Water Imbibition Flooding: An Enhanced Oil Recovery Process for Fractured Reservoirs,". Presented at the Eighth Wyoming EOR Symposium scheduled held in Casper, WY, May 20-21, 1992.
4. Poston, S.W., Perez, J., Edwards, C., and Hervas, A., "MRI Studies of Differential Fluid Movement in Homogeneous and Variable Permeability Cores,". Presented at the Eighth Wyoming EOR Symposium held in Casper, WY, May 20-21, 1992.
5. Perez, J., Poston, S.W., and Barrufet, M.A., "Studies of Carbonated Water Imbibition Using MRI," paper SCA 9221. Presented at the SCA/SPWLA Joint Annual Conference Society of Core Analysts, Oklahoma City, OK, June 14-17, 1992.
6. Barrufet, M.A., Perez, J.M., Mandava, S.S., Ali, L., and Poston S.W., "MRI Studies of Permeability Control Using Polymers," SPE 24809. Presented at the 1992 SPE Annual Technical Conference and Exhibition, Washington, DC.

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.

TASK 4: MATHEMATICAL MODELING

MATHEMATICAL MODELING OF IMBIBITION CARBONATED WATERFLOODS IN NATURALLY-FRACTURED RESERVOIRS

by

C. H. Wu, S. H. Shenawi, and F. J. L. Briens

SUMMARY

Two mathematical models: a semi-analytical model (IMOD) and a 3-dimensional, 3-phase, dual-porosity, compositional simulator (COMABS) are developed to describe the imbibition carbonated waterflood oil recovery performance in naturally-fractured reservoirs.

The IMOD solves the nonlinear integro-differential equation describing the imbibition waterflood performance in a fracture/matrix system. The model is based upon the Buckley-Leverett type flow in a fracture surrounded by matrix blocks. The rate of water imbibition with variable water saturation at the imbibition boundary is represented by a convolution integral. The major achievement of this new model over the published models is that it could determine the oil recovery and saturation profiles for oil to water viscosity ratios other than one. This model is used to describe the laboratory imbibition carbonated waterflood experiments⁴⁹⁻⁵³ conducted on chalk cores in Task 3. The concentrations of carbonated water used are 0.0, 2.3, 4.0 and 5.5 percent by weight of CO₂, respectively. The experiments are carried out at three temperatures: 70 °F, 110 °F, and 150 °F. The calculated imbibition oil recoveries match the experimental results very well.

There are many inherent limitations in the semi-analytical model. To fully describe the complex oil recovery mechanisms involved in imbibition carbonated waterflood oil recovery from low-permeability, naturally-fractured reservoirs, a 3-dimensional, three-phase, dual-porosity, compositional, numerical simulator (COMABS) has been developed. This numerical model is developed based on the dual-porosity continuum theory assuming discontinuous matrix blocks are surrounded by interconnected fractures. The COMABS is used to match the imbibition oil recoveries obtained from the carbonated waterflood experiments.

The COMABS allows partitioning of CO₂ from the injected water phase into the oil phase based upon the CO₂ solubility in each phase. The partitioning causes a reduction in oil phase viscosity and an increase in oil density. It is assumed that the interaction between the carbonated water and carbonate rock alters the wettability of the rock matrix. The interaction causes a reduction in residual oil saturation and necessitates a corresponding

shift of relative permeability curves. The matrix block size is adjusted by the use of geometric shape factor F_s that has a pronounced effect on the rate of oil recovery by carbonated water imbibition. According to the saturation distributions, shock-fronts are formed in the fracture and matrix systems at the higher CO_2 concentration in the injected water. The oil and water saturation profiles in the core affected by relative permeability and residual oil saturation changes are discussed.

The results of this study indicate that both semi-analytical and numerical models provide the detailed analysis of imbibition oil recovery behavior by carbonated waterflood. The semi-analytical model predicts the oil recoveries with relative ease. Hence, the model can be used to screen the potential application of imbibition waterflood oil recovery in a naturally-fractured reservoirs before initiating a full field scale numerical simulation.

SEMI-ANALYTICAL MODELING

The simplifying assumption, f_{wf} equals S_{wf} , made by de Swaan⁵⁴ and by Kazemi et al.⁵⁵ implies that oil to water viscosity ratio M is equal to 1. Therefore, de Swaan's and Kazemi's approaches are not valid when the viscosity ratio is other than one.

The semi-analytical model (IMOD) is developed based on Kazemi et al. model⁵⁵ by eliminating the simplifying assumption that f_{wf} equals S_{wf} . The fracture system governing equation is expressed as,

$$- u_f \left(\frac{df_{wf}}{dS_{wf}} \right) \frac{\partial S_{wf}}{\partial x} = \frac{\partial S_{wf}}{\partial t} + \frac{\lambda R_\infty}{\phi_f} \int_0^t e^{-\lambda(t-\tau)} \frac{\partial S_{wf}}{\partial \tau} d\tau \quad (1)$$

Equation (1) is transformed into the Laplace domain,

$$- u_f \frac{df_{wf}}{dS_{wf}} \frac{d\widetilde{S_{wf}}}{dx} = s \left(1 + \frac{1}{(s + \lambda)} \frac{R_\infty \lambda}{\phi_f} \right) \widetilde{S_{wf}} \quad (2)$$

After applying the initial and boundary conditions, Eq. (2) is solved numerically in the Laplace domain. The Stehfest's numerical Laplace inversion algorithm⁵⁶ is used to invert the fracture water saturations to the real domain.

The oil recovery is calculated from the fractional flow of oil at the grid point where production well is located,

$$R(t) = \left(\sum_{i=1}^t i_w (1 - f_{wf,i}) \Delta t \right) / V_p \quad (3)$$

The water-oil ratio is calculated using the oil and water saturation at the production grid point of the fracture where the fractional flow is assumed to be proportional to saturation.

$$WOR = S_{wf} / S_{of} \quad (4)$$

The matrix system governing equation is expressed as,

$$0 = \frac{\partial S_{wma}}{\partial t} - \frac{\lambda R_{\infty}}{\phi_{ma}} \int_0^t e^{-\lambda(t-\tau)} \frac{\partial S_{wf}}{\partial \tau} d\tau \quad (5)$$

Equation (5) is solved in the same fashion as for Equation (1).

Matching Laboratory Imbibition Carbonated Waterfloods

The core face flushing imbibition experiments⁵¹ at elevated temperatures and pressures are performed on Texas cream chalk cylindrical cores obtained from an outcrop of a formation near Austin. The physical properties of the core samples are listed in Table 3. The concentrations of carbonated water solutions are 0.0, 2.3, 4.0 and 5.5 percent by weight of CO₂ in brine at 70 °F. The oil and water viscosities used are given in Table 4.

Table 3 - Physical Properties of Chalk Cores Used for Core Face Flushing Experiments

diameter of core	= 1 inch	permeability	= 9.1 md
length of core	= 2 inch	ϕ_{matrix}	= 23 %
oil saturation	= 67.6%	ϕ_{fracture}	= 0.39 %
S_{wc}	= 32.4 %		

Table 4 - Kerosene and Water Viscosity

Fluid	Viscosity (cp) at		
	70 °F	110 °F	150 °F
Kerosene	1.10	0.80	0.50
Water	1.00	0.63	0.43

The cylindrical core and the fracture are represented by a rectangular system as shown in Fig. 69.

Fig. 69 - A rectangular system for semi-analytical modeling.

Fig. 70 through 72 show the matching of the imbibition oil recovery at 70 °F, 110 °F and 150 °F, respectively. The data points represent the experimental results and the plotted lines are the calculated results.

Fig. 70 - Matching the imbibition oil recovery at 70 °F.

Fig. 71 - Matching the imbibition oil recovery at 110 °F.

Fig. 72 - Matching the imbibition oil recovery at 150 °F.

Table 5 summarizes the λ values used in matching the experimental oil recovery efficiencies. The values of λ used in the model are adjusted to get a good match with the laboratory data.

Table 5 - Summary of Experimental and Matching λ Values

Type of fluid @ 70 °F	Laboratory 70°F	Model 70°F	Laboratory 110°F	Model 110°F	Laboratory 150°F	Model 150°F
Brine	4.31	2.20	2.72	1.50	2.22	1.60
2.3 %	2.86	2.50	3.08	2.60	3.14	2.20
4.0 %	2.26	2.30	1.92	2.10	1.29	2.20
5.5 %	2.03	2.20	2.18	2.30	6.01	3.00

Fig. 73 shows the correlation of the estimated maximum oil recovery (% OOIP) with the carbon dioxide concentration in carbonated water. More laboratory imbibition carbonated waterflood experiments are needed to provide more definitive conclusions.

Fig. 73 - Effect of CO₂ concentration on maximum recoverable oil by imbibition.

The correlation models for the oil recovery efficiency are as follows:

For 70 °F cases,

$$R_{\max} = 15.810 + 4.5305 (\text{CO}_2 \%)$$

For 110 °F cases,

$$R_{\max} = 19.182 + 11.434 (\text{CO}_2 \%)$$

For 150 °F cases,

$$R_{\max} = 23.701 + 11.166 (\text{CO}_2 \%)$$

NUMERICAL SIMULATION

An existing 3-dimensional, 3-phase, single-porosity, compositional reservoir simulator⁵⁷⁻⁵⁹ is modified to develop a 3-dimensional, 3-phase, dual-porosity, compositional reservoir simulator (COMABS). The IMPES method is used to calculate the pressures implicitly, and the saturations and compositions explicitly. The Peng-Robinson Equation of State⁶⁰ (PR-EOS) is used to perform equilibrium calculations for hydrocarbon liquid and vapor phases. The assumptions made in developing the dual-porosity, compositional simulator (COMABS) are as follows:

1. The dual-porosity approach is valid with no matrix/matrix flow.
2. A pseudo-steady state counter current flow exists between matrix/fracture systems.
3. The diffusional mass transfer between matrix and fracture is negligible.
4. The gravity effect is ignored in the matrix/fracture fluid exchange transfer function.
5. Local thermodynamic phase equilibrium is achieved instantaneously within each grid block.
6. The compositional effect on capillary pressure is negligible.

The fluid exchange between the matrix and fracture system due to capillary pressure gradient is represented by fluid exchange source/sink terms. The matrix/fracture fluid exchange terms are defined by the Darcy's law expressed over some mean path between the centers of matrix blocks and the adjacent fracture blocks. According to the dual-porosity compositional formulation, the governing fluid flow equations for a component c in oil, gas and water phases are as follows.

For the fracture system hydrocarbon phase:

$$\begin{aligned}
 & \nabla \cdot \left[\frac{k k_{ro} \xi_o}{\mu_o} x_c (\nabla p_o - \gamma_o \nabla D) + \frac{k k_{rg} \xi_g}{\mu_g} y_c (\nabla p_g - \gamma_g \nabla D) \right]_f \\
 & - U_{HC}^* + [x_c \xi_o q_o + y_c \xi_g q_g]_f \\
 & = \frac{\partial}{\partial t} [\phi_f (x_c \xi_o S_{of} + y_c \xi_g S_{gf})]_f
 \end{aligned} \tag{6}$$

For the fracture system aqueous phase:

$$\begin{aligned} & \nabla \cdot \left[\frac{k k_{rw} \xi_w}{\mu_w} w_a (\nabla p_w - \gamma_w \nabla D) \right]_f - U_w^* + [w_a \xi_w q_w]_f \\ & = \frac{\partial}{\partial t} [\phi_f (w_a \xi_w S_{wf})] \end{aligned} \quad (7)$$

For the matrix system hydrocarbon phase:

$$U_{HC}^* = \frac{\partial}{\partial t} [\phi_{ma} (x_c \xi_o S_{oma} + y_c \xi_g S_{gma})]_{ma} \quad (8)$$

For the matrix system aqueous phase:

$$U_w^* = \frac{\partial}{\partial t} [\phi_{ma} (w_a \xi_w S_{wma})]_{ma} \quad (9)$$

Where matrix/fracture transfer term U^* is defined for hydrocarbon phase as,

$$U_{HC}^* = F_s k_{ma} \left[\left(\frac{k_{ro} \xi_o}{\mu_o} \right)_{usmaf} x_c (p_{of} - p_{oma}) + \left(\frac{k_{rg} \xi_g}{\mu_g} \right)_{usmaf} y_c (p_{gf} - p_{gma}) \right] \quad (10)$$

and for aqueous phase as,

$$U_w^* = F_s k_{ma} \left[\left(\frac{k_{rw} \xi_w}{\mu_w} \right)_{usmaf} w_a (p_{wf} - p_{wma}) \right] \quad (11)$$

where x_c and y_c represents the mole fraction of a component c in hydrocarbon liquid and vapor phases, respectively. Similarly, w_a represents the mole fraction of a component a in aqueous phase. The COMABS allows the partitioning of CO_2 from the injected water phase into the oil phase based upon the solubility of CO_2 in oil and water phase.⁶¹⁻⁶³

The geometric shape factor⁵⁵, F_s , for a matrix block is:

$$F_s = \sum_{i=1}^{N_s} \frac{A_i}{V_{ma} d_i}$$

The control-volume finite difference approximation technique (CVFD) is used to solve Eqs. (6) through (7). This technique consists in writing the mathematical expressions for the flow into and out of the control-volume, matrix/fracture fluid exchange, and the accumulations of fluids inside the control-volume. This technique generates the symmetrical flow coefficients and checks the mass balances over each of the grid system. The IMPES method is used to calculate the pressures implicitly and the saturations and compositions explicitly.

The laboratory imbibition carbonated waterflood oil recovery performances are simulated using COMABS. A dual 5x1x3 grid system is used to simulate the imbibition process in the core sample as shown in Fig. 74. The carbonated or plain water is injected into block 1x1x3 of the fracture system, and the production well is placed at the block 1x1x1 of the fracture system. Table 6 presents the physical properties of the chalk cores used in numerical simulation. In the fracture system, the capillary pressure is assumed to be zero and straight line relative permeability curves are used. The matrix capillary pressure data⁵⁵ used for this simulation study are shown in Figure 75.

Table 6 - Fracture and Matrix System Properties of the Chalk Cores

<u>Fracture System Properties</u>		<u>Matrix System Properties</u>	
k_x & k_y	= 9000 md	k_x & k_y	= 9.1 md
k_z	= 9000 md	k_z	= 3.1 md
S_{wc}	= 0.0	S_{wc}	= 0.324
ϕ_f	= 0.0039	ϕ_{ma}	= 0.23
P_c	= 0.0	P_c	= $f(S_{wma})$
k_r	= S_{wf}	k_r	= $f(S_{wma})$

The major assumptions made in the simulation of the laboratory imbibition experiments are as follows:

1. The system pressure is high enough to prevent the formation of free gas in the fracture and matrix system.
2. The CO_2 from the injected water phase can be partitioned into the oil phase based on the solubility of CO_2 in oil and water phase.
3. The interaction between the carbonated water and the chalk matrix alters the wettability of rock. The reduction in residual oil saturation as a function of CO_2 concentration shifts the relative permeability curves favorable for improved oil recovery.
4. The dissolution of CO_2 in the oil and water phase does not appreciably affect the capillary pressure.
5. At any point in the system and at any one time, the oil and water phases are in equilibrium.
6. The mutual solubility of water and oil is negligible.

Fig. 74 - Grid system used for the numerical simulation

Fig. 75 - Capillary pressure curve⁵⁵ for the matrix system

When the CO₂ concentration is lower than 0.9 mole fraction, the n-C₁₀ - CO₂ mixture will be in single phase⁶¹ at 70 °F. Similarly, maximum solubility of CO₂ in n-C₁₀ is 0.65 and 0.52 mole fractions at 110 °F and 150 °F, respectively. In the numerical simulation studies, the maximum solubilities of partitioned CO₂ in n-C₁₀ are set at 0.5, 0.3 and 0.2 mole fraction for the system temperature at 70 °F, 110 °F and 150 °F, respectively. The partitioning of CO₂ into the oil phase decreases the oil viscosity and increases the oil density. The density of oil as a function of CO₂ concentration is determined by Peng-Robinson equation of state (PR-EOS) method.^{60,64} The oil viscosity is calculated using Rackett correlation.⁶⁴

Figure 76 shows the relative permeability curves constructed as a function of CO₂ concentration for the simulation runs at 100 °F. The relative permeability curves shift to the right as the CO₂ concentration increases. This shift provides the favorable mobility to oil over water. The COMABS updates the mobility of the oil phase ($k_{ro} \xi_o / \mu_o$) in fluid flow terms depending on the dissolved CO₂ concentration in the oil phase.

Fig. 76 - Matrix relative permeability curves as a function CO₂ concentration (110 °F).

The computed oil recoveries at 70 °F, 110 °F and 150 °F matched the laboratory data very well as shown in Figs. 77 through 79. These figures indicate that oil recovery increases as the CO₂ concentration increases. The geometric shape factors F_s used for the numerical modeling at the three temperatures are as follows:

- 36, 42, 120 and 180 for 0.0, 2.3, 4.0 and 5.5 wt. % carbonated water at 70 °F,
- 30, 35, 100 and 130 for 0.0, 2.3, 2.6 and 3.8 wt. % carbonated water at 110 °F,
- and
- 22, 29, 90 and 110 for 0.0, 1.9, 2.0 and 2.7 wt. % carbonated water at 150 °F.

Fig.77 - Matching of imbibition oil recovery at 70 °F.

Fig. 78 - Matching of imbibition oil recovery at 110 °F.

Fig. 79 - Matching of imbibition oil recovery at 150 °F.

Simulation of an Imbibition Carbonated Waterflood in a Naturally-Fractured Reservoir

To test the applicability of the imbibition carbonated waterflood in a naturally fractured reservoir, a hypothetical linear 10 grid blocks system is used to forecast the oil recoveries by plain waterflood and 4.0 wt. % carbonated waterflood. Table 7 presents the input data used in the hypothetical field-scale simulation.

The shape factor used for the plain and 4.0 wt. % carbonated waterfloods are 0.02 and 0.03, respectively. The relative permeability curves at 110 °F are used. The computed oil recoveries by plain and carbonated waterflood are presented in Fig. 80. Figure 81 shows the computed water and oil production rate performances.

Table 7 - Input Data for A Hypothetical Field Case

Reservoir thickness	= 20 ft
Grid system	= 10 x 1 x 1
Initial reservoir pressure	= 1000.0 psia
Temperature	= 110 °F
Viscosity of water	= 0.6 cp
Location of injecting well	= 1 x 1 x 1
Location of producing well	= 10 x 1 x 1
Water injection rate	= 30 STB/D
Constant production rate	= 30 STB/D
Minimum bottom hole pressure	= 300 psi

For Plain Waterflood

Fracture System Properties

k_x & k_y	= 9,000 md
L_x	= 75 ft
L_y and L_z	= 20 ft
S_{wi}	= 0.0
ϕ_f	= 0.01

Matrix System Properties

k_x & k_y	= 1.0 md
L_x	= 75 ft
L_y and L_z	= 20 ft
S_{wi}	= 0.324
ϕ_{ma}	= 0.23

For Carbonated Waterflood

Fracture System Properties

k_x & k_y	= 9,000 md
L_x	= 75 ft
L_y and L_z	= 20 ft
S_{wi}	= 0.0
ϕ_f	= 0.01

Matrix System Properties

k_x & k_y	= 1.0 md
L_x	= 20 ft
L_y and L_z	= 20 ft
S_{wi}	= 0.324
ϕ_{ma}	= 0.23

Fig. 80 - Oil recovery from plain waterflood and 4.0 wt. % carbonated waterflood.

Fig. 81 - Oil and water production rates from plain waterflood and carbonated waterflood.

TRANSFER OF TECHNOLOGY

The following is a list of the presentations pertaining to the subject:

1. Briens, F.J.L., Wu, C.H., Gazdag, J. and Wang, H.H.: "Compositional Reservoir Simulation in Parallel Supercomputing Environments," SPE 21214 presented at the 11th SPE Symposium on Reservoir Simulation in Anaheim, California, February 17-20, 1991.
2. Shenawi, S.H., Wu, C.H., Jiang, C. and Luan, Z.A.: "A New Iterative Mathematical Model for the Analysis of Imbibition Carbonated Waterflood in Naturally-Fractured Reservoirs," SPE 27717 to be presented in 1994 SPE Permian Basin Oil and Gas Recovery Conference in Midland, Texas, March 16-18.
3. Shenawi, S.H. and Wu, C.H.: "Compositional Simulation of Carbonated Waterfloods in Naturally-Fractured Reservoirs," SPE 27741 to be presented in 1994 SPE Improved Oil Recovery Symposium in Tulsa, Oklahoma, April 17-20.

CONCLUSIONS

Semi-Analytical Modeling:

1. The significant achievement of this model over published models is that it can provide non-linear solutions for the oil to water viscosity ratio other than unity.
2. Modeling results of oil recoveries by plain water and carbonated water in chalk cores indicate the exponential nature of the imbibition process. The calculated imbibition oil recoveries by the semi-analytical model matched very well with the laboratory results.
3. Correlation models are developed for determining the maximum recoverable by imbibition for forecasting the imbibition carbonated waterflood at elevated temperature and various carbon dioxide concentration.

Numerical Simulation:

1. The simulation results indicate that carbonated water enhances the rate of water imbibition into the rock matrix. This results in higher counter current flow of oil from the matrix to the fracture.
2. The saturation distributions in the fracture and matrix systems indicate that CO₂ enhances the rate of water imbibition near the injection well forming shock-fronts in both fracture and matrix systems. The increase in water imbibition into the rock matrix retards the water breakthrough.

3. The geometric shape factor F_s has a pronounced effect on the imbibition rate. Its use in reservoir simulation should be justified with laboratory data.
4. The simulator is capable of simulating the oil recovery performance in uniformly fractured and/or non-fractured reservoirs.

NOMENCLATURE

A_i	=	surface area exposed to imbibition, [ft ²]
d	=	distance from the matrix boundary to the center of matrix [ft]
D	=	depth, [ft]
f	=	fractional flow, [fraction]
F_s	=	geometric shape factor for an imbibing matrix block, [1/(ft ²)]
i_w	=	water injection rate, [ft ³ /D]
k	=	absolute permeability, [md]
k_r	=	relative permeability, [fraction]
M	=	oil to water viscosity ratio, [fraction]
N_s	=	a number of matrix block surface exposed to fracture
p	=	pressure, [psi]
q	=	volumetric flow rate, [SCF/D]
R	=	imbibition oil recovery, [fraction]
R_∞	=	maximum recoverable oil by imbibition from a unit matrix block, [fraction of bulk volume]
s	=	parameter in Laplace space
S	=	phase saturation, [fraction]
t	=	time, [D]
u	=	interstitial velocity, [ft/D]
U^*	=	matrix/fracture fluid transfer term, [lb-mole/(RCF-D)]
V	=	volume, [ft ³]
w	=	mole fraction of a component in aqueous phase
x	=	spatial variable, or mole fraction of a component in HC liquid phase
y	=	mole fraction of a component in HC vapor phase
z	=	overall mole fraction
λ	=	reciprocal of time required to produce 63% of recoverable oil in place, [D ⁻¹]
ϕ	=	porosity, [fraction]
τ	=	Integration parameter for time dependent terms, [D]

ξ	=	molar density of a phase, [lb mole/RCF]
γ	=	gravity gradient of a phase, [psi/ft]
μ	=	viscosity, [cp]

Subscripts

f	=	fracture
g	=	gas
HC	=	hydrocarbon
ma	=	matrix
max	=	maximum recoverable oil
N	=	north side of the block
o	=	oil
p	=	pore or phase
usmaf	=	upstream matrix or fracture
w	=	water
wc	=	connate water

3.3 - Field Test and Transfer of Technology

TASK 5: FIELD TESTS

FIELD CASE HISTORY STUDIES

by

S. W. Poston and J. M. Perez

A CO₂-enriched water imbibition flood was attempted on the Edco Energy #1 well. Approximately 10,000 bbl of 90 scf CO₂ per bbl of water were injected. The well has come back strong. The new decline curve is presently being evaluated.

TRANSFER OF TECHNOLOGY

by

S. W. Poston

Two, transfer of technology symposiums on the Austin Chalk producing trend were held on the Texas A&M campus during 1992.

The first meeting was held on June 3, 1992. The Petroleum Engineering Department at Texas A&M University sponsored the meeting. There was a large turnout with 194 attendees who were principally from 52 oil companies, 26 service companies and the Texas Railroad Commission.

The second meeting was held on October 23, 1992. Attendance was 110 with 50 different oil operators and 5 service companies comprising the total. Three copies of the proceedings are enclosed. ?

These meetings ^{were} ~~are~~ designed to attract the independent operators in the Austin Chalk and will continue in the future

Abstract says 3 meetings

expand this section considerably - Describe problems - Describe well - depth, agg, etc. production

4.0 - Conclusions

Geological Studies - Significant advances have been made 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 and analysis of daily production data, from field case histories, have shown the utility of the Chen Type Curves to derive reservoir character from production test data. This information 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 cores with a single open fracture as compared to cores with an open fracture intersected by a dead end fracture. The artificial pressure depletion 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.

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APPENDIX

CHARACTERISTICS OF NATURAL FRACTURES IN THE AUSTIN CHALK OUTCROP TREND*

by

Kevin P. Corbett**, M. Friedman***, D. V. Wiltschko*** and J. Hung***

INTRODUCTION

The development of natural fractures in outcrops of the Austin Chalk were studied to gain a better appreciation of fracture orientation, spacing and development relative to local and regional structure, lithology and stratigraphy. The purposes are to provide the data and the confidence to extrapolate those data into the subsurface so as to enhance prediction of fracture development in Austin petroleum reservoirs.

This study derives from forty days of field work during July and August of 1990. The principal field localities (Figure 1) are (a) Tequesquite Creek where it crosses U.S. Highway 277 between Del Rio and Eagle Pass, (b) the roadcut on the northwest side of U.S. Highway 90 immediately west of the Nueces River, five miles (8 km) west of Uvalde, (c) the Alamo and Longhorn Cement Quarries in San Antonio, (d) the Lehigh cement quarry in Waco, and (e) the Lafarge cement quarry in Dallas. At all of these localities detailed maps of the fracture systems as observed on bedding surfaces were constructed at scales ranging from 1:12 to 1:48. Additionally, 14 detailed traverses were made along horizontal scanlines placed on subvertical quarry walls. Each scanline was chosen to sample a different orientation relative to local and regional structure. Along each traverse fracture spacing and the length of fractures in the dip direction were recorded along with fracture surface morphology. A total of over 1200 fractures were measured along the scanlines.

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At each locality the fractures were mapped and studied relative to exposed local structure (i.e., anticlines, monoclines, listric normal faults and grabens). Moreover, we concentrated on structures similar in size to those occurring in the subsurface along the Austin play. Fracture development relative to these structures will be described after the presentation of some general data on the fracture development. These, in turn, will be followed by a discussion of the degree to which data on outcrop fractures can be extrapolated to the subsurface.

GENERAL FRACTURE DEVELOPMENT

Several observations are important to an overall understanding of fracturing in the Austin Chalk as follows:

1. The general fracture development suggests that the Austin Chalk deformed in a very brittle manner. This is supported primarily by (a) the abundance of extension (or tensile) fractures as indicated by surface morphology of hackle marks, arrest lines, and plumose configurations, and en passant fracture trajectories (see 2, below), and (b) the development of mostly extension fractures and shear fractures wedging or converging into extension fractures.

2. Closely-spaced, parallel extension (or tensile) fractures that have propagated toward one another typically show the "en passant" configuration. That is, the parallel fractures pass and join-up at nearly right angles, presumably only after stress concentrations at their tips no longer interfere. Based on linear elastic fracture mechanics, this morphology means that relatively small differential stresses existed at the time of fracturing (Pollard and Aydin, 1988). Small differential stress is consistent with failure of the Austin Chalk under a relatively thin overburden (perhaps 3,500 ft, [1.1 km] based on vitrinite reflectance temperatures of 90°C [Cloud, 1975, and Corbett, unpublished data]) at these outcrop localities during the time of deformation. Small differential stresses

and low effective pressures would promote very brittle fracturing of the chalk.

3. Fractures tend to be bed-contained when marl breaks between chalk beds exceed a thickness of about 4 in (10cm). When the marl beds are thinner the fractures penetrate more than one bed whether they are associated directly with an obvious structure or not (Corbett et al., 1987). The marl breaks apparently become stratigraphically more abundant and thicker toward the northeast along the trend from about Waco, and west of Uvalde along the southwestern extension of the trend.

4. The average fracture spacing is about 3 to 4 inches (7.5 to 10 cm) along scanlines oriented at 60° to 90° to the local strike of the structural trend (Figure 2). This is about half of the fracture spacing along lines oriented at 0° to 30° to the structural trend. Since the scanlines are parallel to the trajectories of horizontal boreholes, these data confirm the practice and results from the subsurface Austin play that horizontal drilling perpendicular to the local trend intersects more fractures than otherwise.

5. Fracture spacing for all data at Dallas, Waco, San Antonio and Uvalde show that most of the fractures are spaced less than 15-inches (38-cm) apart and that fracture spacing follows a negative exponential distribution (Figure 3).

6. Many fractures are filled with sparry calcite. Preliminary measurements of fluid inclusions suggest the calcite was precipitated at temperatures in excess of 150°C.

7. Fractures at many locations are paralleled in detail by color banding in the host rock. This color banding arises from chemical reactions between fluids and rock with fluids migration controlled by the fractures. Cross-flow between fractures and matrix is clearly indicated.

STRUCTURE RELATED FRACTURES

Plunging Anticlinal Flexures. A gently plunging anticline, probably a flexural-slip fold, is well exposed at Tequesquite Creek. The fold studied in detail is part of a wavetrain with a wavelength of about 260 ft. (80 meters). It has an amplitude of < 10 ft. (<3 m) and plunges 7° SW. It is likely that this structure is doubly plunging in accord with other folds in the area, but limited exposure precludes study NE of the crest. The Dessau Member of the Austin Chalk crops out at this locality (Pessagno, 1969). The rock is well indurated and is relatively strong in triaxial compression tests, although it is weaker (due to a larger smectite clay component) than samples with equivalent low porosity from the Atco Chalk and Big House Chalk Members of the Austin (Corbett et al, 1987).

Two well-ordered fracture sets and one poorly ordered array are present on this structure (Figure 4a). The major set consists of long, continuous fractures that are nearly vertical and strike N50E (parallel to the axis of the anticline). Typically they range up to 50 ft (15 m) in length and generally exceed 15 ft (5 m) in dip-length, which is the limit of the outcrop exposure. They are evenly spaced about 3 ft (1 m) apart. Upon close inspection, each of these major fractures actually is composed of two or three parallel fractures about < 1.0-inch (0.5 to 2.0 cm) apart. All other fractures on this fold terminate against this set of major fractures. Fractures of this orientation are commonly developed on folds in general and may be the extension fractures of assemblage #2 (Stearns, 1968; Stearns and Friedman, 1972).

The second ordered fracture set intersects the first at angles >70°. Dips range from 60° to 90° NE or SW, with an average dip of 80° in either direction. Spacing of this set is more variable than for the major set ranging from 4 to 60 inches (0.1 to 1.5 m) and averaging about 26 inches (0.65m). Their strike-length (about 40 inches, [1 m]) is fixed by the spacing of the major set while the dip-length averages about 14 inches (0.35m) and is controlled by bedding thickness, i.e., these fractures tend to be bed-contained. Fractures of similar orientation also are common on many folds.

The third fracture array is unordered and found only along the crest of the anticline. These fractures also are completely contained by fractures of the major set. They are highly variable in strike- and dip-length with the

former controlled by the spacing of the two ordered sets and the latter by bed-thickness.

Monoclinial Folds. Exceptional cross section exposures of monoclinial folds are present in the Longhorn cement quarry in San Antonio. These structures are NW facing, possess horizontal upper and lower limbs, and a gently dipping (5° to 8°) interlimb between their anticlinal and synclinal hinges. They are located within a half mile (400 to 800 m), but not directly adjacent to NW dipping faults of the Balcones system. Total structural relief ranges between 16 and 26 ft (5 and 8 m) across a horizontal distance of about 165 ft (50 m). At this locality the base of the Atco Chalk Member is exposed within 16 ft (5 m) of the underlying Eagleford Shale. The Atco Chalk Member here has a relatively high porosity (about 24%) and relatively large amounts of smectite and other clays (Corbett et al., 1987).

Four fracture sets are developed in these flexures (Figure 4b). The first two sets form a conjugate pair of steeply-dipping fractures that have a common strike of $N20^{\circ}E$ (parallel to the axis of the monocline). Each has an average dip of 60° but the NW-dipping fractures are roughly twice as abundant as the SE-dipping set. The NW-dipping set has preferentially developed into small displacements faults with offsets ranging from 4 to 80 inches (0.1 to 2.0 m) and they are localized by pre-existing calcite/clay-filled veins. In composite the NW-dipping set and the mineralized veins account for the folding seen at a smaller scale. If related simply to curvature, these fractures should show greatest abundance along the anticlinal hinge. However, their highest intensity is in the vicinity of the short interlimb and synclinal hinge. These conjugate sets would make the greatest contribution to the fracture porosity and permeability of the structure.

The other two fracture sets also strike $N20^{\circ}E$. One set commonly develops into small faults with a dip range from 10° NW to 30° SE (see insert, Figure 4b). This set shows shear displacements from 0.5 to 12 in. (1 to 30 cm). The other set is composed of steeply dipping calcite- and clay-filled fractures or veins ranging in dip-length from 4 to 40 inches (0.05 to 1.0 m). The nature of the cliff outcrop precluded determination of strike-length. The shallowly dipping fractures (small faults) are localized by groups of veins.

They exhibit dip-lengths ranging from 3 to 17 ft (about 1 to 5 m). These two sets would probably have low permeability perpendicular to their surfaces but because of partial filling and cataclastic shearing they would afford high permeability parallel to their surfaces.

Listric Normal Faults. The best exposures of listric normal fault systems are in the Alamo cement quarry in San Antonio and the Lehigh cement quarry in Waco. Here we concentrate on the Alamo quarry fault as it is the larger structure and accordingly more comparable to subsurface exploration targets. The Atco Chalk Member is exposed in the Alamo quarry (Dravis, 1979) and the structure of interest is approximately 100 ft (30m) above the contact with the underlying Eagleford Shale.

The listric fault system (Figure 4c) is composed of a master fault which accounts for virtually all of the displacement, several subsidiary faults of minor displacement in both the hanging wall and footwall, and genetically related shear and extension fractures. The master fault consists of a 60°-dipping headwall segment, a listric segment with small radius of curvature, and a horizontal-sole segment localized within a thick marl interbed. Subsidiary footwall faults are (a) all steeply dipping and parallel to the headwall segment, (b) closely spaced (40 to 80 inches [1 to 2 m]) and (c) located within 16 ft. (5 m) of the master fault. In contrast, hanging wall subsidiary faults range from steep- to shallow-dipping and are truncated by and merge with the sole segment of the master fault. Hanging wall subsidiary faults show a systematic increase in spacing with distance from the master fault and are present up to 115 ft (35 m) away from the master fault.

At the Alamo quarry the master fault has 33 ft (10 m) of stratigraphic throw. Subsidiary footwall faults, of which there are three, have a total stratigraphic throw of 8 ft (2.5 m), while the eight subsidiary hanging wall faults have a total throw of 6 ft (1.8 m). The master fault and footwall subsidiary faults all contain clay and calcite filled veins which are directly analogous to those found in the monoclinial folds (see above). It is worth noting that veins of this type are characteristic of the entire outcrop trend and are also recognized in the subsurface (Corbett, 1982 and unpublished data).

The master and footwall subsidiary faults have dip-lengths in excess of 100 ft (30 m), the limit of outcrop exposure. Dip-length of the faults in the hanging wall decreases from 40 ft (12 m) directly adjacent to the master fault to 6 ft (1.8 m) at a distance of 115 ft (35 m). Both the footwall and hanging wall exhibit a set of vertical extension fractures, but these fractures are 1.5 times more abundant in the hanging wall as they are in the footwall. Fracture length shows the same trend as fault length in the hanging wall, while in the footwall the length is generally limited by bed thickness. The fractures become progressively more bed-contained with distance from the main fault.

Graben-in-Graben Normal Faults. The cross-graben structural style (Figure 4d) is best displayed from Waco north along the outcrop trend. It is characterized by the development of orthogonal-striking faults and the corresponding genetically-related fracture sets. Conjugate faults of the northern Balcones system form the dominant fault set with SE-dipping faults invariably displaying significantly greater offset than NW-dipping ones. Contained within these faults are conjugate faults which strike perpendicular to the Balcones system. The result of these nested faults is to produce a keystone block within a Balcones graben. This block has 1.5 times the fracture intensity of the remainder of the graben and 2.5 times that in the adjacent horst block.

EXTRAPOLATION OF OUTCROP FRACTURE DATA TO SUBSURFACE

In what respects are fractures in the outcrop similar to those in the subsurface? This is a legitimate question in that our measurements are made largely in quarries (a) subjected to rock operations although no blasting, and (b) fractures might occur in the outcrops due to relaxation phenomena at rock/air interfaces. If the latter were true the fractures would probably relate to stresses related to the deformation, but their opening would be enhanced by the relaxation. In addition, overburden and corresponding temperatures probably were different along the current outcrop trend compared to that at depth at the same time of fracturing. None-the-less, investigations of fracture morphologies, vein systems and fault fabrics from cores (Corbett et al. 1987) suggest that the mechanisms of fracture formation in the subsurface are similar to those we have identified in the outcrop trend.

Accordingly, we believe the outcrop data can be used to predict fracture development in the subsurface in the following ways, namely:

1. The orientation of major outcrop fractures sets may be used reliably to determine the direction of horizontal or inclined boreholes. This is especially true if fractures are partially filled with clay and or sparry calcite because the latter are unlikely to have formed due to surface processes.

2. Relative fracture abundance/orientation trends may also be reliably used to: (a) choose the direction of proposed borehole deviations, (b) predict fractures near faults, particularly fracture development in hanging wall versus footwall and size of fracture halo, (c) predict fractures in flexures and folds, particularly fracture orientation and size of halo, (d) understand the controls of stratigraphic members, marls breaks, and bed-containment, and (e) predict the influences of differences in grain size, porosity, and clay content on rock strength (Corbett et al., 1987) with the idea that in the brittle regime the stronger rocks will contain the largest fracture surface area upon deformation.

3. Average intact block sizes or fracture spacings determined from outcrop studies may be too small by some as yet unknown factor.

SUMMARY AND CONCLUSIONS

Preliminary analysis of our field data has provided insight into fracture development in the Austin Chalk, much of which probably can be extrapolated into the subsurface. In addition to detailing the brittle fracture development, we have identified four distinct structural styles (Figure 4) which result in higher fracture intensities than in surrounding flat-lying beds. The small plunging anticlinal flexure is perhaps analogous to the Pearsall Field provided the fracture intensity, orientation and mode of fracturing scale from the small to the larger structure, as expected. The monoclinial flexure and listric normal fault settings appear to be directly analogous in size, style and origin to similar structures in the Giddings Field. Consequently, they provide excellent analogue models for development

drilling. Finally, the graben-in-graben structure to our knowledge has not been identified in the subsurface and may offer potential for an as yet unrecognized reservoir type.

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Figure 1. Location map of Texas showing Austin Chalk outcrop trend with sample locations shown as open circles. Abbreviations: BFS = Balcones fault zone, LFZ = Luling fault zone, M-TFZ = Mexia-Talco fault zone, ETE = East Texas embayment, RGR= Rio Grande embayment. Subsurface structure contours (C.I. = 5,000 ft) are on top of Austin Chalk. (From Corbett et al., 1987; reused with permission of the AAPG).

Figure 2 Plot shows average fracture spacing along each of the 14 scanlines, with the angle of intersection defined as the angle between the orientation of the scanline and the trend of adjacent major structure such as fold axis or fault strike.

Fracture Spacing (inches)

Figure 3. Plots show fracture spacing data from all scanlines at each of the four localities. The vast majority of the fractures are spaced less than 15-in. apart and the overall distribution is negatively exponential.

Fracture Spacing Class (cm)

Figure 1. Histograms of fracture spacings for all data. Spacing is defined as the distance between intersections of fractures with the scanline.

SUM OF FRACTURES/4 LOCALITIES

Figure 3b. Compilation of all data in Figure 3 into one plot.

PLUNGING ANTICLINE

a.

MONOCLINAL FLEXURE

b.

LISTRIC NORMAL FAULT

c.

**GRABEN-IN-GRABEN
NORMAL FAULTS**

d.

Figure 4. Schematic illustrations of structural types and associated fractures described in text.

Controls on Fracture Development, Spacing, and Geometry in the Austin Chalk

Formation, Central Texas:
Considerations for
Exploration and Production

Field Trip Leaders:

Kevin P. Corbett
Melvin Friedman
David V. Wiltschko
Jih Hao Hung

Annual
Convention

Dallas Geological Society
Field Trip #4
April 6-7, 1991

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Guidebook
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Controls on Fracture Development, Spacing, and Geometry in the Austin Chalk Formation, Central Texas: Considerations for Exploration and Production

Kevin P. Corbett
Melvin Friedman
David V. Wiltschko
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Introduction

Horizontal drilling has made fractured reservoirs attractive exploration targets. The Austin Chalk Formation, as a consequence of this new technology, has been one of the most extensively pursued exploration targets in the continental United States for the last several years, particularly in the number of production wells drilled in the Pearsall and Giddings fields, Texas. In spite of the advantages horizontal drilling offers for enhancing initial and total production, successful operations still are predicated on the location of zones of high fracture intensity and a high density of fracture intersections. Often, these zones are not directly detectable from seismic surveys. Consequently, the most viable strategy for success to date has been to offset highly productive wells along strike. Accordingly, the purpose of this field trip is to observe fractures in outcrops of the Austin Chalk with a view towards providing conceptual models of fracture development and corresponding data for extrapolation into the subsurface.

In order to enhance predictability of these high fracture intensity regions in the subsurface, we investigated the outcrop trend of the chalk to identify the tectonic environments where high fracture intensities are found. We used two techniques to assess the characteristics of the fracture systems. First, we measured the length, spacing, and orientation of fractures along scan lines on vertical quarry walls. Second, we made detailed maps of the fracture systems as exposed on bedding surfaces, at scales ranging from 1:12 to 1:48. We paid particular attention to investigating domains comparable in style, character, and size to currently producing subsurface structural settings. Accordingly, these well exposed and extensively studied outcrop structures can then serve as direct corollaries in identifying exploration targets and in improving the siting and geometry of production boreholes.

We have identified four tectonic environments and associated structural settings possessing statistically higher fracture intensities and more

long *master* fractures, which are one of the principal controls on increasing effective drainage area (Corbett and others, 1991). Additionally, we have statistically characterized the general form of the distribution of several fracture parameters including spacing, length and orientation.

Our studies also indicate that at least two discrete episodes of fracturing have occurred. The earliest of these episodes is apparently attributable to the development of abnormally high pore fluid pressure in the chalk. Several lines of evidence, including fluid inclusion trapping temperatures, trace element abundances, the stable isotope characteristics of vein filling calcite, and an order of magnitude increase in smectite clay in veins compared to chalk matrix, leads us to identify this first fracturing episode as a natural hydrofracture event. The hydrofractures influenced the location of major structures produced during the second fracture episode, and to a degree have determined the location of faults and master fractures during this second event. We believe it is essential to understand the genetic development of the composite fracture system in order to formulate a complete fracture model.

On this field trip we will inspect three of the four tectonic environments we have identified along the outcrop trend, a listric normal fault system, a monoclinial flexure, and a graben-in-graben normal fault system. The fourth environment, an anticline, is located near Del Rio in southwest Texas, making a visit to this locality impractical. At each location there will be ample opportunity to inspect the spatial, geometric, and temporal properties of the fracture systems. We will discuss facets of the stress state, at the time of formation, which can be discerned from fracture surface morphology and fracture interactions. We will also review the statistical properties of the fracture systems for each specific locality, and the geochemical and mineralogical aspects of the hydrofracture veins.

The field guide is divided into two sections. In the first section we present general observations, properties, and attributes of the fracture systems, discuss the development of the hydrofractures and present a conceptual model for their formation. In this section we also discuss the statistical analysis of the

fracture data, and general aspects of fracture mechanics. In the second section we present the specific details of the outcrops we will inspect. Particularly salient aspects of each outcrop are identified, and our interpretations of the origin and evolution of these specific examples are put forth for discussion. Since we feel that these localities are likely candidates as analogue models for producing structures, we are vitally interested in eliciting your observations, interpretations, and conclusions so that we may test, refine, and where necessary redefine our current hypotheses.

We trust you will find the trip intellectually stimulating and beneficial to you in your own exploration and production efforts in the Austin Chalk and other fractured reservoirs. We look forward to the opportunity to interact with a diverse group of active explorationists and broaden our understanding of natural fracture systems.

Geologic Setting

The regional geologic setting, sedimentology, diagenesis, and stratigraphy of the Austin Chalk Formation has been established by other workers and references to the pertinent literature are provided in Corbett and others 1987. Here we summarize those aspects of the regional geology and tectonics pertinent to the outcrops we will visit.

The Austin Chalk crops out throughout Texas, from Red River County in the northeast to Val Verde County in the southwest (Figure 1). Both the surface and subsurface trends follow the form of the Gulf Coast miogeocline. In central Texas the outcrop belt is coincident with the Balcones fault system. This fault system parallels the structural grain of the Paleozoic Ouachita deformed belt, which is exposed to the northwest in the Llano uplift and Texas Hill Country. It may be inferred, but cannot be proved, that the location and trend of the Balcones system is the result of an existing weak zone in the underlying Ouachita basement rocks. Regardless of any basement control, the general style of faults in the Balcones system indicates that they formed in response to down-to-the-coast extension of the sedimentary prism. In this respect, they are

Figure 1. Geographic reference map showing Upper Cretaceous outcrop (stippled), subsurface structural contours on the top of the Austin Chalk (dashed lines), The Balcones fault system (BFS), Luling fault zone (LFZ), Mexia-Talco fault zone (M-TFZ), and the Rio Grande and East Texas embayments (RGE, ETE) of the Gulf Coast miogeocline (reproduced by permission from Corbett and others, 1987).

similar to other, younger faults in the Gulf Coast region. The age of Balcones system faulting is not tightly constrained, as no cross-cutting stratigraphic relationships have been preserved. All sediments younger than Cretaceous and older than Quaternary have been removed by erosion. Therefore, the age is established by analogy with the tectonically similar, subsurface, Luling, Mexia, and Talco fault zones (Figure 1). These zones affect rocks as young as Oligocene but apparently do not offset Miocene strata (Weaks, 1945).

As a consequence of Balcones system faulting, exposures of the chalk are more extensive than other formations. Nevertheless, natural exposures are limited, confined primarily to stream beds. The best exposures occur in cement quarries in Dallas, Waco, and San Antonio. In particular, these quarries afford the only opportunity to examine fractures, faults, and related

structures on the bedding surface, and in two approximately vertical and orthogonal profile planes. While nowhere are all three surfaces directly linked, they do provide a composite, three-dimensional view of the fracture systems.

Durham (1957) studied the chalk in the Austin area and erected a stratigraphic section composed of one formal member, the Atco Chalk Member, and six informal ones. Subsequently, Pessagno measured and formally described chalk sections from southwest Texas, Waco, and Dallas (Figure 2). All quarries except the Longhorn Quarry in San Antonio are within the basal Atco Chalk Member (Dravis, 1979; Cloud, 1975). The Longhorn Quarry exposes middle and upper Austin Chalk on either side of a large displacement Balcones system fault (Cloud, 1975). The contact with the underlying Eagleford Shale is not exposed in the San Antonio quarries. At the Waco and Dallas quarries the contact and underlying shale are exposed. Subsurface stratigraphy can be correlated with the outcrop section based on gross lithologic similarity, as reflected in electric log response (Figure 2; Corbett and others, 1987; 1991).

The Atco Chalk Member is composed of rhythmically bedded chalk-marl sequences. The chalk beds generally range from 0.5 to 2 m thick and are separated by marls ranging from 0.5 to 15 cm thick. The thickness of intervening marl beds increases from San Antonio north, attaining a maximum in the Dallas area. The thickening of intervening marls coincides with a concurrent thickening of the basal Atco Chalk Member. Both circumstances are a consequence of the original depositional setting. At the time of chalk deposition the San Marcos Arch (Figure 1), a subsurface extension of the Llano uplift, formed a topographic high (Murray, 1961; Young, 1963). Chalk strata, particularly the basal Atco Chalk Member, are thinned across this depositional high and thicken both to the northeast and southwest, where deposition was in the deeper-water basinal settings of the Rio Grande and East Texas embayments. The increase in marl thickness is likewise a result of variation in depositional setting, from shallow shelf on the San Marcos Arch to more basinal away from the arch.

Champlin Petroleum
Lancier Brinkman #1
Burleson County, TX

Figure 2. Correlation of outcrop and subsurface stratigraphic sections for the Austin Chalk (adapted from Corbett and others, 1987).

The mineralogy of the Atco Chalk Member is relatively uniform. It ranges from 85% to 91% calcite, with quartz and clay minerals representing the only significant minor components (Corbett, 1982; Corbett and others, 1987). Quartz occurs primarily as microscopic, euhedral crystals ranging from 5 μm to 10 μm in size. Clay minerals occur as large amorphous masses ranging from 30 μm to 80 μm in size. These accessory phases most likely were derived from syn-depositional volcanic ash, as discrete ash layers are found higher in the formation, and contemporaneous eruptive centers have been identified (Lonsdale, 1927). Diagenesis of the Atco Chalk Member is relatively mild in central Texas, showing a moderate increase in overgrowth cement from Dallas south to San Antonio (Cloud, 1975). Scanning electron microscopy reveals only minor dissolution of the fragmented coccolith tests which compose the bulk of the rock matrix (Cloud, 1975; Dravis, 1979). Dravis (1979) inferred that fresh water diagenesis dominated the central

Texas outcrop belt, based primarily on the removal of aragonite macrofossil material. Alternatively, Cloud (1975) argued for early burial diagenesis, based on texture and stable oxygen and carbon isotope compositions. Our textural observations and geochemistry (Corbett, 1982; and this study) support Cloud's interpretation.

It has been proposed that the Austin Chalk may be a self sourcing reservoir (Grabowski, 1984; Hunt and McNichols, 1984; Hinds and Berg, 1990). According to this theory fracturing accompanies oil maturation and is related to high pore fluid pressures generated by hydrocarbon expulsion. Considering the variability in oils recovered from the Austin Chalk throughout the productive subsurface trend, it seems unlikely that this mechanism is universally responsible for fracturing and oil formation. Perhaps detailed source rock - oil comparisons can establish the validity and applicability of this hypothesis.

General Fracture Characteristics

Fractures

Fracture nomenclature is controversial and in a state of flux. Workers in the fields of rock mechanics, structural geology, petroleum engineering, and civil engineering do not attach the same meaning to a particular term, or may use different terms to refer to one feature or process (Engelder, 1987; Pollard and Segall, 1987; Pollard and Aydin, 1988). Therefore, to avoid ambiguity we define the terminology used in this report in the short discussion which follows. Diagrammatic representations of the fracture and fault types are shown in Figure 3.

A fracture is any planar discontinuity in a rock mass produced by brittle failure. The failure process may have been aided, enhanced, or accelerated by chemical reactions with the pore fluids, but is fundamentally a result of mechanical breakdown of rock mass integrity. A simple extension fracture forms perpendicular to the direction of the least principal compressive stress. It represents a discrete failure event in both space and time. A joint is a composite surface resulting from the coalescence of two or more simple extension fractures. These may form during a discrete failure event, but more commonly result

Figure 3. Schematic representations of fracture, vein, joint, and fault characteristics. a) A conjugate set of shear fractures and their relationship to the principal stress directions; σ_1 greatest, σ_2 intermediate, and σ_3 least principal stresses. b) A vein filled extension fracture with horsetail fracture tips. c) A joint composed of three extension fractures each with characteristic hackle and plume structures showing direction of fracture propagation. Note the en-passant fracture tip relationship shown on the bedding surface. d) Characteristic geometry of a listric normal fault with an antithetic fault in the hanging wall.

from progressive failure as evidenced by fracture surface markings and fracture tip interactions (Pollard and Aydin, 1988; Engelder 1985). As such, joints are generally not discrete failure events in either space or time.

Shear fractures are failure surfaces inclined at an angle ranging from 15° to 45° to the maximum compressive stress at the time of failure. They often form conjugate sets (Stearns, 1964; Friedman, 1975), but this is not requisite. Shear fractures are characterized by differential offset of the two rock masses on either side of the fracture surface (ie. they have accommodated shear displacement), but the magnitude of shear displacement may be too small to observe in the field. In reality, shear fractures and faults describe a continuum in displacement. We distinguish shear fractures as those shear surfaces having a net displacement which is less than 0.1% of the fracture length in the displacement direction. Although in principle this criteria is unambiguous, true fracture length is not always exposed in the field, sometimes rendering distinction between shear fractures and faults impossible. Nevertheless, it is desirable to have a clear working definition for classifying shear fractures.

A vein is any fracture which is partially or completely filled by minerals which crystallized in the opening created by the fracture. Generally, vein minerals precipitate from pore fluids which invade the fracture during or after formation.

Four types of fractures are present in Austin Chalk outcrops. In all cases vein-filled fractures were first to form as indicated by cross-cutting relationships. Simple extension fractures, joints, and shear fractures developed after the vein filled fractures. The origin and relative timing of these latter fractures depends on the tectonic setting in which they are found.

Faults

We classify those faults, or segments of a fault, where the dip exceeds 50° as high-angle faults. Faults which dip between 30° and 50° are intermediate-angle faults, and those with a dip of 30° or less are shallow-angle faults. Listric faults are characterized by continuous

variability in dip angle from a high-angle headwall segment, through an intermediate-angle knee segment to a shallow-angle sole segment. Listric faults result in rotation of hanging wall strata in the vicinity of the headwall and knee segments of the fault (Figure 3).

Listric and high-angle normal faults are the most common fault types. They have produced horst-and-graben and graben-in-graben structures respectively. Each possesses increased fracture intensity and enhanced development of master fractures. The third fault type develops on monoclinial flexures. These faults are sub-parallel to bedding, allowing for extension perpendicular to the fold axes during the early stages of fold growth. Later, high-angle normal faults accommodated continued fold growth.

Vein systems

Vein filled fractures were the first systematic fracture set to form. They are cross-cut by all other fracture and fault surfaces. Individual veins range from $100\ \mu\text{m}$ to 30 cm in length and from $10\ \mu\text{m}$ to 5 mm in width (Figure 4). They generally occur in en-echelon swarms, with 5 cm to 25 cm wide zones of high vein density separated by barren zones 100 cm to 1 m wide. Fracture tips for the veins frequently exhibit a wispy, horsetail appearance, which indicates low stress concentration at the tip and low deviatoric stress. The vein fill is composed primarily of two phases, calcite and a mixed-layer, smectite-illite clay. The clay minerals were deposited first on the vein walls and subsequently were overgrown by subhedral calcite crystals. Many of the veins exhibit crack-seal texture (Ramsey, 1980), demonstrating multiple fracture episodes.

Several lines of evidence indicate that the most plausible origin for the veins is a series of natural hydrofracture events. Comparison of vein geochemistry with that for the bulk chalk suggests that extra-formational pore fluid was introduced to the chalk. We postulate that introduction of this fluid into the chalk raised the pore fluid pressure triggering fracturing and vein formation.

We determined vein clay mineralogy by analyzing the acid insoluble residue from

Figure 4. Typical vein characteristics in the basal Atco Chalk Member. a) Vein swarm cut by a small displacement fault; Lafarge quarry, Dallas. b) Thin-section photomicrograph of two parallel vein systems; Old Alamo Quarry, San Antonio. One vein system shows a left-stepping, en-echelon relationship, photo is 1.5 mm wide.

powdered samples on the Cameca SX-50 microprobe at Texas A&M University using a 20 keV, 10 nA beam, a 2 μm beam size and count times of thirty seconds for major elements and sixty seconds for the minor elements fluorine and titanium. Trace element abundances for vein calcite were also determined by microprobe analysis using a 10 keV, 20 nA beam, with a spot size of 10 μm . Low concentrations for the principal trace elements: strontium, manganese, and iron, necessitated count times of 5.5 minutes while count times of thirty seconds were used for the major and minor elements calcium and magnesium. We established an empirical linear regression relationship between counts per second and concentration for each trace element (Table 1), and used this relationship to recalculate trace element abundances and normalized the total to 100%.

TABLE 1

ELEMENT	R	n	CPS/0ppm
Sr	0.919	25	31.07
Mn	0.947	28	43.46
Fe	0.743	26	5.06

Fluid inclusion measurements were made on a Leitz Ortholux microscope equipped with a heating-cooling stage. Reproducibility for T_m (melt temperature) and T_h (homogenization temperature) was $\pm 0.1^\circ\text{C}$. Stable isotope analysis of the vein calcite was performed by Dr. Ethan Grossman, Texas A&M University. We report all isotopic values as δC^{13} - δO^{18} PDB. We have used the relevant trace element and stable isotope data for bulk chalk samples reported in Cloud (1975) and Dravis (1979) as our basis of comparison.

Clay minerals are much more abundant in veins than they are in the chalk matrix. They constitute 4% to 9% by volume of outcrop chalks (Corbett and others, 1987). Smectite clays, including the proportionate share of mixed layer clays, range between 1% and 4% by volume in the chalk. In veins, clay minerals range from 18% to 25% by volume. They are dominantly mixed-layer smectite-illite with a 2:1 to 3:1 ratio. The interlayer cation for the smectites is most likely Ca, but our separation and analysis technique precludes an unequivocal determination. The location of

the clay minerals on vein walls is well illustrated by energy dispersive maps of elemental abundance for a microprobe thin section (Figure 5).

Trace element composition of the vein calcites is distinctly different from that for bulk chalk samples (Figure 6). Most striking is the discrepancy for the large incompatible element strontium, which will preferentially go into solution when calcite dissolves (Veizer, 1983). None of the median values of strontium for the veins overlap the first quartile of either set of bulk samples. All of the veins are depleted in strontium with respect to the bulk samples. This is opposite to the expected outcome if the vein calcite were derived from local chalk dissolution and reprecipitation. Likewise, the veins are depleted in Fe and Mn with respect to the bulk chalk samples, again in contrast with results expected based on a local dissolution-reprecipitation model. No clear trend for the minor element magnesium is apparent, most of the vein samples possess median values between the first and third quartiles for one of the groups of bulk samples. Noteworthy, is the generally much greater variability in magnesium abundance in the veins as compared to the bulk samples. In view of the crack-seal textures this scatter may reflect different degrees of fluid-chalk interaction prior to a specific hydrofracture event.

Stable isotope data for the vein calcite clearly points to an extra-formational source for the veins in the Dallas and Waco areas. These veins are preferentially depleted in O^{18} compared to the bulk chalk samples (Figure 7). In the Del Rio area the vein calcite is slightly depleted in O^{18} and enriched in C^{13} in comparison with the chalk matrix. This is not surprising as the interbedded marls in the Dessau Chalk and Burditt marl members provide a local source for vein forming pore fluids. For the San Antonio area the vein calcite and bulk chalk samples have comparable stable isotope characteristics. Two bulk samples from Cloud (1975) are strongly depleted in C^{13} . These samples appear to be anomalous and may indicate contamination. Exclusive of these samples, the vein calcites in San Antonio are compatible in their stable isotope composition with either local derivation or equilibration with the chalk matrix.

Al Map

Si Map

Finally, fluid inclusions in the vein calcite suggest derivation from an extra-formational source. Three populations of inclusions may be distinguished based on salinity and homogenization temperature (Figure 8). Textural relationships, including size, shape, and distribution suggests that these are primary inclusions trapped during formation of the vein calcite from pore fluids. For San Antonio two groups of inclusions are evident. One group is in the range 1 to 4 weight percent NaCl, while the second group ranges from 6 to 10 weight percent NaCl. The mean homogenization temperatures are $T_h=186^\circ\text{C}$, and $T_h=183^\circ\text{C}$ for each group respectively. For the three Waco measurements the salinities are comparable, but the homogenization temperatures are lower than for San Antonio. Disregarding the one anomalously low value, which we believe is a secondary inclusion formed in the near surface environment, the remaining two Waco measurements yield a mean T_h of 134°C . The homogenization temperatures provide a minimum estimate of the original fluid temperature at the time of trapping. Temperature estimates derived from vitrinite reflectance values for bulk chalk samples are substantially lower than the fluid inclusion temperatures (Table 2). The most straight forward interpretation of this discrepancy is that the fluids from which the vein minerals precipitated were derived from a deeper, hotter source.

The crack-seal texture of many veins and horsetail fracture tips require a pore fluid pressure equivalent to the least principal compressive stress. Furthermore, the crack-seal texture indicates multiple fracturing and vein forming episodes. The vein minerals are almost completely undeformed. No fracturing of vein deposits is evident and mechanical twins in the coarse-grained, sparry calcite are extremely rare. There is no preferred crystallographic fabric orientation of the vein

Figure 5. (at the left). A back-scattered electron image of a dense vein swarm which has been rotated and sheared in a fault zone. Elemental maps of aluminum and silicon demonstrate the concentration of clay minerals along vein walls and on the brittle shear surfaces; Longhorn Quarry, San Antonio.

a

SRPPM

b

MNPPM

c

FEPPM

d

MGPPM

Figure 6. Comparison of minor and trace element compositions between the bulk chalk matrix and vein calcite. Bulk samples are from Dravis (1979) drv, and Cloud (1975) cld. Vein samples kpc1... and kpc2... from Longhorn quarry, San Antonio, w1 from Lehigh quarry, Waco. Box and whisker plots show the median value for sample population with vertical bar in box, left and right box boundaries delimit the first and third quartiles respectively, whisker ends show boundaries for 5% and 95% of the sample population, outlier values are indicated by an asterisk. a) Veins are strongly depleted in strontium compared to bulk chalk. b) Veins are strongly depleted in manganese with respect to bulk chalk. Cloud (1975) did not measure manganese. c) Veins are strongly depleted in iron with respect to bulk chalk. d) Veins show a much larger scatter in magnesium content than bulk chalk. For further discussion see text.

STABLE ISOTOPES BULK CHALK AND VEINS

Figure 7. Plot of δO^{18} versus δC^{13} for bulk chalk and vein calcite, bulk samples are those reported in Cloud (1975) except where noted in the legend.

Fluid Inclusions Veins

Figure 8. Plot of homogenization temperature (T_h) in degrees celsius versus weight percent NaCl for fluid inclusions in vein calcites. Key to symbols: squares, Longhorn quarry, San Antonio; crosses, Lehigh quarry, Waco.

TABLE 2

SAMPLE NO. & LOCATION	REFLECTANCE	ESTIMATED TEMP. °C
ZGE Dallas*	0.71	108
ZGI Dallas*	0.74	110
ZEA Dallas*	0.76	111
ZEI Austin*	0.81	118
SAL-1b San Antonio	0.70	107
ZAR Del Rio*	0.79	116

* Data from Cloud, 1975. Temperatures calculated using the kinetic model of Burnham and Sweeney (1989).

calcite (Corbett, 1989), in spite of the incorporation of many veins into fault zones. This lack of preferred orientation suggest crystallization occurred under a hydrostatic stress state.

The textural characteristics and virtually all of the geochemical evidence indicates that the vein forming fluids were derived from outside the chalk and from deeper in the basin. These fluids evidently infiltrated the chalk and eventually reached a pressure sufficient to promote fracturing. The increase in pore volume produced by fracturing resulted in the pore fluid pressure returning to a value below that of the least principal stress. Crystallization of the vein minerals, first clays and then calcite, was triggered by the pressure

drop. The combination of vein mineral growth and continued infiltration of pore fluid resulted in this scenario being episodically repeated. How this invasion of fluids from below relates to possible self-hydraulic fracturing of the chalk associated with oil maturation is unknown.

Hypotheses

Our current working hypothesis is that the chalk was under a state of low differential stress, but generally near failure. Increasing the pore fluid pressure had the effect of equivalently reducing all principal stresses, thereby leaving the differential stress unchanged and producing failure (Figure 9).

Figure 9. Conceptual model for the generation of high pore fluid pressure and resultant natural hydrofracturing of the Austin Chalk. Pore fluids driven from the Eagleford shale, due to compaction beneath a thick overburden section in the more distal portion of the sedimentary prism, migrated up-dip along the shale, invaded the chalk and produced extension fractures which propagated upwards from the contact. Frequently faults developed concurrent with fracturing.

The large volume of smectite clay in the veins, along with depletion of trace elements and the high fluid inclusion homogenization temperatures for calcite, indicate to us the most likely source for the fluids is dewatering of the underlying Eagleford Shale. We envision a hydrodynamic system where fluid expelled by compaction from the Eagleford Shale flows up-dip, along the shale, until it encounters comparatively high permeability zones in the overlying chalk. The fluid invades the chalk at these zones and eventually reaches a pressure sufficient to produce fracturing (Figure 9). The close relationship between veins and faults poses a chicken-and-egg question, which came first. Certainly, faults would serve as ideal high permeability conduits for pore fluids to invade the chalk. We are inclined to believe, from observations on small faults in a rhythmically bedded chalk-marl sequence in the Burditt Marl Member near Del Rio, that the veins and faults frequently develop simultaneously. As fluid from the shale invades the chalk, the shale experiences local compaction initiating faulting at the chalk-shale bedding surface (Figure 10).

An alternative hypothesis is that relating oil maturation to self-hydrofracturing. This hypothesis is incapable of explaining the foregoing geochemical considerations, particularly the fluid inclusion homogenization temperatures, and thus appears unlikely as a candidate for explaining the outcrop vein systems. However, it may be more viable in describing subsurface fracturing. Both hypotheses need to be tested further. In either case abnormally high pore fluid pressures would be generated, resulting in low effective stresses for both the outcrop and subsurface environments at the time of fracturing. This condition permits extrapolation of outcrop fracture data into the subsurface.

We note that these vein systems are not restricted to the outcrop trend, but are also found in the subsurface (Figure 10). Again they are associated with faults. The vein/fault fabric indicates that the veins were forming during fault displacement. Although we have only identified this one occurrence from the subsurface, we suspect that these veins are commonly developed but go unrecognized, unless a core is obtained and adequately preserved for structural study.

The location of faults, folds, and associated high fracture intensities was evidently controlled by the location of the veins. Two aspects of the vein systems served to localize later deformation. First, the inception of faulting in many cases occurred prior to complete crystallization of the veins. Primary evidence for this is the S-C type fabrics developed in many of the fault zones (Figure 11). This fabric results from rotation of the veins during fault displacement. The latest formed veins demonstrate that the fault zone walls are perpendicular to original vein orientation. Lack of a preferred crystallographic fabric for the calcite crystals in the rotated veins indicates that crystallization followed rotation. Thus, the implication from the S-C fabrics is that the veins had not completely crystallized at the time of faulting, and were at least partially fluid-filled fractures. The veins constituted a location for the initiation of shear failure, the fluid-filled vein swarms being unable to support a shear stress. This first faulting event was ductile in character and did not result in formation of an open fracture networks.

A second important consideration is the veins introduced and concentrated appreciable amounts of smectite clay in the chalk. We previously identified smectite clay as a significant control on rock strength in experimentally deformed chalk samples (Corbett and others, 1987). For those experiments, we noted that increasing smectite content from 0% to 1% by volume was sufficient to decrease chalk strength by a factor of two (Figure 12). Further increases in smectite content continued to decrease chalk strength, but at a reduced rate. The very high concentration of smectite clay in veins as compared to the chalk matrix (Figure 5) resulted in the veins being exceptionally weak elements in the rock mass. As such, the veins again served as macroscopic flaws and initiated failure. All faults show at least two displacement episodes, one during vein formation, as indicated above, and a brittle episode following complete vein crystallization. It is during this second faulting event that the role of smectite clay in the failure process is important. The open fracture networks developed during this second deformation episode. Whether these two events represent a continuum of deformation we do not know. However, their

Figure 10. Small displacement faults and natural hydrofractures. a) Systematic set of natural hydrofractures in rhythmic chalk-marl sequence in the Burditt Marl Member of the Austin Chalk at Sycamore Creek, 15 miles southeast of Del Rio. Note the preservation of greater chalk bed thickness adjacent to the fractures. Arrow in 10a shows location of small displacement fault shown in detail in 10b. b) Small displacement fault (2 cm) localized by a vein swarm in 12 cm thick chalk bed. Fault displacement rapidly decreases to 0 in overlying and underlying marl beds.

Figure 10. (continued). c) Thin-section photomicrograph of a small displacement fault localized by and deforming a vein swarm in basal chalk section from the Exxon G. Longenbaugh #1. Sample from -7005 feet, photo is 0.25 mm tall, crossed nicols.

very different character suggests they are discrete and separate events.

Fracture Statistics

Regardless of the specific structural setting, several characteristics of these later fracture populations are similar. Both fracture length and spacing, measured on scan lines, show a negative exponential distribution (Figure 13). Accordingly, most fractures are small and closely spaced. Smaller fractures show less preferred orientation than larger fractures

(Figure 14). Overall, fracture populations from each locality show similar, moderately well-developed preferred orientation. At all localities two orthogonal fracture sets are present (Corbett and others, 1987). The orientation of the master fractures was evidently controlled by the orientation of major faults and folds. The master fractures strike parallel with these structures and generally have dips near vertical.

Master fractures appear in some cases to have periodic spacing. Plots of fracture length versus distance along a scan-line suggest that

Figure 11. S-C type fabrics developed where veins forming the S-fabric were rotated by fault displacement and later cut by brittle shear surfaces forming the C-fabric. a) Gouge sample from a fault with approximately 2 m of stratigraphic throw, Longhorn quarry, San Antonio. b) Whole thin-section photograph of sample in (a) shows the variability in offset of different vein swarms as indicated by the variability in vein rotation, thin-section is 4 cm wide, crossed nicols.

Figure 12. Plot of strength versus smectite content for experimentally deformed samples of the Atco Chalk Member reported in Corbett and others (1987) demonstrates the rapid reduction in strength with increasing smectite content.

the longer fractures recur with a predictable frequency (Figure 15). Indeed, these plots resemble a waveform with fracture length equivalent to amplitude, spacing equivalent to wavelength, and the apparent decrease in fracture length with distance from faults indicating a damping function. Since these data are irregularly spaced they are not amenable to standard methods of time series analysis. We are currently investigating several modeling strategies using non-linear estimation algorithms. Our first goal is to predict fracture length as a function of distance along a scan-line. If we are able to realize this first objective, we will then seek to determine the underlying physical process responsible for the repetition.

Brittle Fracture Characteristics

Fracture surface features and the interaction of fracture tips indicate the chalk behaved in a very-brittle fashion (Figure 16). Plumose and hackle structures are commonly developed on fracture surfaces. The hackles are generally of high relief indicating a comparatively fast

velocity for joint propagation (Pollard and Aydin, 1988). Commonly, fractures initiate and/or terminate at faults, other fractures and bedding surfaces. Shear fractures can be seen to merge into extension fractures. In experimental rock deformation this is associated with very brittle failure (Handin, 1966), especially at very-low effective pressure. Extension fractures commonly show an en-passant relationship, where the stress field at the tip of an existing fracture influenced the trajectory of another fracture propagating towards it. The second fracture tip curves away from the first as it approaches and overlaps it. When it is beyond the influence of the localized stress field associated with the tip of the first fracture, the second fracture tip curves towards the first fracture and merges with it, and vice-versa. The en-passant relationship suggests "a relatively low, far-field differential stress, since a large differential stress would negate the small local perturbation produced by the fracture tip. Relative timing for fractures of different orientation, as inferred from cross-cutting relationships, is dependent on specific structural setting. We discuss the cross-

a

b

c

d

e

f

Figure 13. Plots of frequency versus length and spacing (reported in inches) respectively for fracture populations from Dallas (a & b), Waco (c & d), and San Antonio (e & f).

a

WACO ALL

c

SAN ANTONIO ALL

e

b

WACO ALL

d

SAN ANTONIO ALL

f

Figure 14. Plots of Strike and dip versus fracture length (reported in inches) for Dallas (a & b), Waco (c & d), and San Antonio (e & f).

DALLAS LINE 1

WACO LINE 1

SAN ANTONIO LINE 4

WACO LINE 2

Figure 15. Plots of fracture length (reported in inches) versus cumulative distance along scan-lines tend to have a periodicity which resembles a waveform with a characteristic frequency and amplitude, particularly for the longer master fractures.

Figure 16. Surface features and styles of fracture interaction. a) En-passant juncture of fracture tips for a joint forming fracture set, bedding plane view, Old Alamo Quarry, San Antonio. b) Plume structure and very-coarse hackle marks show horizontal propagation for this vertical, NE trending extension fracture which terminates at a cross-fracture, Old Alamo Quarry, San Antonio.

Figure 16. c) Plumose structure shows this vertical, NE trending fracture propagated vertically, initiated at a shallow-dipping fracture and terminated against another shallow-dipping fracture, Old Alamo Quarry, San Antonio. d) Shear fractures wedging into an extension fracture, bedding plane view, Old Alamo Quarry, San Antonio. Note the banding produced by multiple invasion episodes of oxidizing, vadose zone, groundwater.

cutting relationships with respect to each field locality in the second section of the guide.

Fractures and fluid flow

Abundant qualitative evidence indicates that fractures are preferred avenues for fluid flow (Figure 17). All of the quarry sites have excavated below the top of the water table. The upper quarry levels were within the vadose zone which is characterized by white to buff colored, bleached, oxidized chalk. Below this zone of alteration the chalk is generally a medium grey color where it is unoxidized. Additionally, pyrite in the alteration zone, in fracture fillings and burrows in the chalk matrix, is almost completely weathered to hematite and limonite. Below the alteration zone pyrite is unaffected. Infiltration of oxidizing vadose zone water, selectively along fractures into the zone of saturation, is evident from the bleached zones surrounding fractures in the zone of saturation. Generally, these alteration halos are symmetric with respect to the fractures. The halos are banded reflecting variation in depth of matrix penetration for specific fluid compositions. Characteristically, three alteration regions can be recognized outward from a fracture. There is an outermost band of buff colored chalk, its outer limit marks the oxidation front, and its inner limit is marked by the limonite front. The middle band is a brown to ochre color due to limonite staining, it lies between the limonite front and the flushed front. The innermost band is a white color and straddles the fracture. The absolute width of these alteration bands is variable at a specific locality and between localities.

Numerous factors affected the depth of alteration, including the chemistry of the vadose zone waters, depth below the top of the water table, length of exposure to vadose zone waters, dilution of vadose zone waters within the zone of saturation, and repetition of vadose water invasion. This last effect is demonstrated by numerous concentric alteration bands around some fracture sets.

For petroleum production the following attributes of groundwater flow along and across fractures appear to be significant: (1) Closed, tight fractures, some partially filled with vein minerals, have much higher permeability than the chalk matrix, as evidenced by the alteration bands mantling fractures originally below the water table in the zone of saturation. (2) Very minor differences in fluid density were evidently sufficient to drive fluid flow along the fractures for appreciable distances. Higher density vadose zone waters flowed down fractures for tens of meters into the zone of saturation. (3) Permeability of the chalk matrix perpendicular to fractures appears to be homogeneous based on the symmetry of the oxidation bands mantling the fractures. (4) Depth of matrix penetration is a function of numerous factors, but chemistry of the invading fluids which controls fluid density differences, depth of invasion below the water table, and total time for the invasion process are likely controlling factors. (5) Fracture orientation appears to have little effect on the transmissivity of vadose zone waters into the zone of saturation. (6) Vadose zone alteration extends to greater depth along fault zones and folds, the areas of higher fracture intensity.

Figure 17. Alteration zones produced by invasion of oxidizing, vadose zone groundwater into the zone of saturation. a) Oxidation front (white) and limonite front (dark grey) around an isolated extension fracture in grey chalk, Lafarge quarry, Dallas. b) Selective permeability along fractures is displayed by fracture swarm containing the fracture in (a).

Description of Field Localities

Old Alamo Cement Quarry, San Antonio

The old Alamo Cement Quarry is located at the southern end of the city of Alamo Heights, in north suburban San Antonio. The main entrance to the quarry is off Jones-Maltzberger Road near the intersection with Tuxedo Drive. Access to the quarry is restricted, permission to enter should be obtained in advance from the Alamo Cement Company, P.O. Box 34807, San Antonio, Texas 78265. The quarry was abandoned in 1982 and is currently being in-filled and reclaimed. The property is for sale. Thus, the availability of this locality for future study is questionable. You may note with some wonder the proximity of relatively high-priced homes to the quarry rim (Figure 18). It seems certain that pressure from these affluent home owners will influence the future use of this location.

Approximately 75 m of chalk is exposed at this location, all within the basal Atco Chalk Member. The deepest level of the quarry is below the current water table, producing a small pond. The floor of this level is approximately 3 m above the Austin Chalk-Eagleford Shale contact. The chalk is characterized by rhythmic bed sets, intervening marls are generally less than 1.0 cm thick, but range up to 30 cm. Internal structure in the chalk beds is mostly lacking, save for occasional burrows or macro-fossil fragments. The chalk is essentially homogeneous and massive.

One of the primary features of interest at this location are the very-long joints which are well exposed, in profile, in the deepest quarry

Figure 18. Systematic joint set developed at the base of the Atco Chalk section in the Old Alamo Quarry, San Antonio.

level, and in map view on the adjacent quarry floor (Figure 18). The principal structural setting observable here is a listric normal fault system exposed in profile on a north-south trending quarry wall. Additional fracture characteristics well displayed at this location are fracture surface markings, fracture tip interactions, and selective permeability along fractures and the associated alteration bands, and the containment of fractures to individual beds by very thin marl breaks exclusive of the joints and away from faults.

The joints have an average strike of N40E and are vertical. In the dip direction their lengths range from 1 m to more than 4 m, which is the limit of exposure. In the strike direction they have lengths ranging from 1 m to more than 12 m. Spacing between joints varies from 0.2 m to 2.5 m, averaging 1.0 m. Pyrite, clay and sparry calcite vein mineralization is variably present along the joints. The joints have widths of less than 0.1 mm to 4 mm, wider zones are typically filled with vein minerals. Plumose structures on joint faces show that individual fractures originated at bedding surfaces, propagated vertically to the center of an individual bed and then propagated laterally. Individual fractures which comprise the joints range in strike length from 5 cm to 2.5 m, with their dip length equal to or less than the thickness of the bed in which they formed. Fracture tips most commonly display an en-passant relationship in map view, but en-echelon relationships are also present. Fractures with an en-echelon relationship are preferentially left-stepping.

We interpret the vein-filled fractures exposed at higher levels in the quarry as equivalent in age and origin with the fractures which form the large systematic joints. While the vein mineralization is not identical to that in the joints it is similar, and the differences appear related to stratigraphy. Pyrite is not as abundant in higher-level veins, evidently because it was derived primarily from pyritized burrows which are common only near the base of the section. Otherwise, both sets of veins possess equivalent vein mineralogies. Additionally, they have the same orientation, and are the oldest fracture system present. They are invariably cut-off by faults and all other fractures terminate against them.

Of particular interest is the observation that the vein-filled fractures only form a systematic joint set at the base of the formation. We speculate that this may be a consequence of their origin as hydrofractures associated with dewatering of the Eagleford Shale. Near the base of the formation, and the source of the invading fluids, the joints were formed by propagation of fractures upwards into successively higher beds. As distance from the underlying shale increased, the localization of the fluid-pressure differential decreased due to bleed-off into the surrounding chalk matrix. This could result in discontinuous fractures at higher stratigraphic levels controlled by zones of high matrix permeability, rather than continuation of the joint system.

We have made a map at a scale of 1:24 of a portion of the floor of the Alamo quarry in a location about 200 m from the area of the joints and listric fault system (Figure 19). Our purpose was to better characterize the fracture network, especially mutual intersections or fracture connections. Interconnectivity has been shown to be directly related to the hydraulic conductivity of a fracture network. Our goal was to characterize the directional nature of the connectivity and thereby better predict, at least qualitatively, directions of easy fluid flow.

A remarkable aspect of the mapped fractures in this quarry, which are distant from major faults, is the lack of connections. The fracture network is characterized by a strong preferred orientation of fractures and relatively less dispersion than in other quarries to be visited on this trip (Figure 20). Due in part to the good preferred orientation the fractures on this map display, on average, there are only 2 connections per fracture, or 1.4 on a per foot of fracture basis. In addition, there is a greater proportion of "blind" or completely unconnected fractures at this level of exposure than in other quarries we will visit: the percentage of blind fractures is even greater in other parts of the quarry. Similarly, of those that are not blind, nearly 90% have a free end, or fracture tip, unconnected to other fractures; only 7% of all fractures abut other cracks on either end. This connectivity is directional because there is a high preferred orientation to the fractures (Figure 20). However, because a significant portion of the fractures are filled with minerals, it is unclear how directional the

Austin Chalk Fracture Map,
Old Alamo Cement Quarry

LARGER FRACTURE —————
 ALTERATION FRACTURE - - - - -
 SMALL FRACTURE - - - - -
 FRACTURED WITH MINOR FILLING - - - - -

Figure 19. Map of a portion of the quarry floor of the Old Alamo Cement Quarry, San Antonio. The mapping was done at a scale of 1:24. A large percentage of the fractures are altered or filled and isolated from other fractures.

Figure 20. Plots of data from the Old Alamo Quarry map. a) Frequency plot of fracture orientation. One well developed fracture set exists. b) Plot of length versus orientation. The most prevalent set also harbors the longest fractures. c) Fracture connections (or intersections with other fractures) per foot versus fracture length versus orientation. The average connections per foot are greater for the well-developed fracture set. d) Number of connections versus orientation. The absolute numbers of connections is greatest for the longest fractures, as is to be expected.

hydraulic conductivity would be at the present time.

Attributes of the joint system which may be important for exploration and production include the following: (1) Our observations suggest that in an extensional environment well-developed systematic joints are restricted to the basal 10 m of the chalk. This may be a consequence of formation by the natural hydrofracture process. (2) Joints are near vertical and strike parallel to the regional structural grain. (3) Joints are partially vein filled and may require stimulation to achieve acceptable permeability and production.

The listric fault system at this location is composed of a main fault which accounts for virtually all of the displacement, several subsidiary faults of minor displacement in both the hanging wall and footwall, and related shear and extension fractures (Figure 21). The main fault has a headwall segment which has a maximum dip of 60°. The knee segment is a displacement transfer zone, where the headwall segment fault dies-out into the hanging wall, with a commensurate increase in displacement on the fault surface

which becomes the sole fault segment. The sole segment roots in a 30 cm thick marl interbed in the chalk sequence. Subsidiary footwall faults are all steeply dipping and parallel to the headwall segment of the master fault, they are spaced 1 m to 2 m apart. In contrast, hanging wall subsidiary faults range from steep to shallow dips and are both truncated by and merge with the sole segment of the main fault. Hanging wall subsidiary faults show a systematic increase in spacing with distance from the main fault and are present up to 35 m away from the main fault. The main fault has 10 m of stratigraphic throw. Subsidiary footwall faults, of which there are three, have a total stratigraphic throw of 2.5 m, while the eight subsidiary hanging wall faults have a total stratigraphic throw of 1.8 m. The main and footwall faults are located in a zone of high vein density. They have truncated and rotated earlier formed veins, and been the site of later vein formation. Subsidiary faults in the hanging wall are devoid of vein mineralization.

The main and footwall subsidiary faults have dip lengths in excess of 30 m, the limit of outcrop exposure. Dip length of the hanging

Figure 21. Listric normal fault system and associated fractures. a) View of the entire fault system shows the increased fracture intensity in the hanging wall compared to the footwall. Arrows indicate the headwall and sole segments of the main fault, note 1.5 m tall individual for scale.

Figure 21. (continued).
 (left). Listric normal
 fault system and
 associated fractures. b)
 Detail of the headwall
 and knee segments
 shows antithetic faults,
 displacement transfer in
 the knee segment, and
 small-displacement
 footwall faults parallel to
 the headwall segment.

Figure 21. (continued).
 (below). Listric normal
 fault system and
 associated fractures. c)
 Detail of the sole segment
 (individual pointing)
 show faults and shear
 fractures in the hanging
 wall are synthetic to the
 main fault and are spaced
 progressively farther
 apart away from the
 headwall segment.

wall faults decreases from 12 m directly adjacent to the main fault to 1.8 m at a distance of 35 m. Both the footwall and hanging wall possess a set of vertical extension fractures, but these fractures are 1.5 times as abundant in the hanging wall as they are in the footwall (Figure 22). Fracture lengths show the same trend as fault length in the hanging wall, while in the footwall the length is generally limited by bed thickness, i.e., the fractures are bed contained. Two sets of shear fractures also are present. The first set is synthetic to the main and subsidiary faults in the hanging wall, and is restricted to the hanging wall. These fractures decrease in abundance, decrease in length, and increase in spacing away from the main fault, against which they truncate. The second set of shear fractures is conjugate to the first and antithetic to the main fault. In contrast with the first set, these fractures are present in both the footwall and hanging wall. They terminate against faults and first set fractures. The fracture and fault relationships are depicted schematically in Figure 23.

The following aspects of listric normal fault systems appear to be viable concerns for exploration and production: (1) Subsidiary footwall faults parallel the high-angle segment of the main listric fault and are within 5 m of the high-angle segment. Fracture intensity away from the subsidiary faults in the footwall decreases rapidly. (2) The hanging wall is more highly fractured than the footwall, and long, through-going, master shear fractures synthetic to the main fault are restricted to the hanging wall. (3) For master fractures, length decreases and spacing increases with distance away from the main listric fault suggesting an optimum horizontal drilling distance may be established.

Figure 22. Scan lines across the listric normal fault system shown in Figure 21. main fault is indicated by an arrow. a) 21 in thick chalk bed. b) 43 in thick chalk bed.

Figure 23. Schematic illustration of a listric fault system.

Longhorn Cement Quarry, San Antonio

The entrance to the Longhorn Cement Quarry is located off Perrin-Beitel Road near the intersection with Schurtz Road. This quarry also is owned by the Alamo Cement Company, and again entrance is allowed only after obtaining prior permission.

Approximately 15 m of the middle and upper Austin Chalk are exposed at this location (Cloud, 1975). The depth to the underlying Eagleford Shale is not known. In most respects the chalk here is very similar to that exposed in the Old Alamo Quarry. The principal difference is the degree of weathering and oxidation. Since these exposures were much closer to the original land surface, they are more strongly weathered than the outcrop we viewed in the morning.

Two monoclinial flexures and their associated faults, vein systems, and open fracture network are the structures of primary interest at this locality (Figure 24). The best developed S-C fault fabrics occur in the fault zones which have produced these monoclinial folds. Also of interest is a large, high-angle normal fault. Quarrying has resulted in excellent exposure of the slickensided fault surface, and the 10 cm to 15 cm thick, sparry calcite vein material which fills the fault zone.

The monoclines exposed here are NW facing, possess horizontal upper and lower limbs, and a gently dipping (5° to 8°) interlimb between their anticlinal and synclinal hinges. They are near (400 m to 800 m), but not directly adjacent to NW dipping faults of the Balcones system. The total structural relief across these folds, from their upper to lower horizontal limbs, ranges between 5 m and 8 m across a horizontal distance of 50 m.

Four ordered fracture sets are developed in conjunction with these fold structures (Figure 24). The vein filled fractures constitute the first two fracture sets. There are two dominant orientations for these extension fractures, one group (1A) strikes N20E parallel to the trend of the monoclinial folds with dips near vertical, the other group (1B) strikes the same direction but dips range from

10° NW through horizontal to 30° SE. Since these vein-filled fractures are mutually cross-cutting they must have formed simultaneously. The approximately horizontal set indicates that pore fluid pressures were abnormally high and may have approached the overburden pressure (Corbett, 1989). These fractures are variable in dip length ranging from 5 cm to 1 m. The essentially cliff exposure precluded direct determination of the strike length for all fractures associated with these monoclinial folds.

A conjugate set of shear fractures constitutes the second fracture set. They strike N20E and dip from 10° to 30° SE and NW, but exhibit preferential development of SE dipping fractures. They are approximately twice as abundant as their NW dipping counterparts, and have overprinted the earlier formed, shallowly-dipping extension fractures. Frequently, the SE dipping shear fractures have developed into small faults which were localized by both groups of veins (Figure 24). The displacement across these faults is variable, ranging from 1 cm to 30 cm. Their dip length is also highly variable ranging from 1 m to 5 m. These faults apparently accommodated lateral translation during the initial stages of fold growth. They probably allowed for flexural slip in the absence of thick intervening marls or other weak beds which could accommodate nearly horizontal displacement.

Steeply-dipping conjugate shear fractures which cross-cut and offset the faults of the second set constitute the third fracture set. These fractures again strike N20E, but shows unequal development of the two conjugate orientations. Each group in the conjugate set has an average dip of 60° , but NW dipping fractures are roughly twice as abundant as SE dipping fractures. As with the shallowly-dipping conjugate set, the more abundant NW dipping fractures have preferentially developed into small displacement faults. These faults also contain the rotated veins characteristic of the shallowly dipping, second set faults. Offset across these NW dipping faults ranges from 10 cm to 2 m, and in composite they

Figure 24. Monoclinical folds and associated fractures and faults. a) Large Balcones system fault with coarse calcite vein filling and 200 m wide monoclinical flexure in the hanging wall. b) Monoclinical flexure produced by numerous small faults has 8 m of relief across a distance of 50 m. Arrows show the location of highest fracture/fault intensity.

Figure 24. (continued).
Monoclinial folds and
associated fractures and
faults. c) Detailed view
of high fracture/fault
intensity in the short
interlimb of the flexure
between the anticlinal
and synclinal hinges.

Figure 24. (continued).
Monoclinial folds and
associated fractures and
faults. d) Low-angle
fault which allowed for
flexural slip during the
early stages of fold
growth is cut by later
high-angle fault which
fans-out into a series of
four shear fractures.

Figure 24. (continued). Monoclininal folds and associated fractures and faults. e) Low-angle fault with resistant weathering, S-C fabric vein gouge is offset by later high-angle faults which merge and also contain S-C fabric vein gouge. f) Conjugate set of low-angle shear fractures.

account for the folding seen at a smaller scale. If these faults were related to fold curvature they should show the highest intensity along the hinges. However, the highest intensity is in the vicinity of the short interlimb. We interpret all three fracture/fault sets as having formed in response to development of the monocline as a drape fold above a buried fault. The fault and fracture distribution on these structures is shown schematically in Figure 25.

EXTENSIONAL MONOCLINAL FLEXURE

Figure 25. Schematic illustration of monoclinial flexures and associated faults and fractures.

Several observations about the style of fracturing on the monoclines may be relevant to exploration for and production from these structures. (1) The highest fracture intensities are in the interlimb region between the anticlinal and synclinal hinges. (2) Shear fractures and small faults greatly predominate over extension fractures on these folds. Shallowly-dipping shear fractures and small faults are well developed. This suggests that, to optimize borehole-fracture intersections in this structural setting, a shallowly-descending deviated borehole is preferable to a horizontal

borehole. (3) Most of the shear fractures and small faults are vein filled, suggesting that stimulation will enhance permeability and well performance.

A major Balcones system fault is exposed in three-dimensions by the quarrying operation. Throw on this fault exceeds the height of the outcrop which is approximately 35 m. The fault zone varies from 10 cm to 30 cm wide and is filled with very-coarse-grained vein calcite. These calcite crystals have grown from the fault-zone walls towards the center and show the dog-tooth crystal habit. Vuggy space remains in the center of the veins, indicating in conjunction with the crystal habit that they grew into open space. The fault zone walls, and vein walls within the fault zone, are prominently striated, demonstrating that at least part of the displacement history post-dates vein formation. Notably, the vein calcites are completely undeformed, even though present in the shear zone during displacement. Footwall strata within 2 m of the fault zone are much more indurated than further away or than hanging wall strata. Evidently footwall strata adjacent to the fault were cemented by the same fluids responsible for vein mineralization. Close inspection reveals numerous, small, isolated veins in these rocks. We believe this fault served as a dewatering conduit for over-pressured fluids from the underlying Eagleford Shale. We infer that this and other major Balcones system faults developed after the monoclinial flexures, because veins were evidently necessary for the formation of the small faults which produced the folds and would be less likely to form if large faults capable of alleviating the over-pressure in the underlying shale were already present. Since hanging wall strata show no rotation towards the fault zone, and the fault plane shows no decrease in dip, it is unlikely that this fault has a listric geometry.

Lehigh Cement Quarry, Waco

The Lehigh Cement Quarry is located approximately 6 miles west of Woodside off U.S. Highway 84 at 100 Wickson Road, Waco. The quarry is owned by the Lehigh Portland Cement Company, P.O. Box 2576, Waco, Texas 76702-2576. Access to the quarry site is restricted and only available with prior authorization. This quarry site was abandoned in 1987. Consequently, the outcrop here is fresher than in either of the San Antonio quarries.

Approximately 30 m of the Atco Chalk Member is exposed in the quarry. The contact with the underlying Eagleford Shale is exposed at several localities in the main quarry, and extensively exposed in the shale pit. Lehigh Cement quarried the Eagleford Shale for illite clay, which was used as an additive in cement production. The chalk here is characterized by beds ranging from 25 cm to 3 m thick. Marl interbeds are thicker here than in San Antonio, ranging from 4 cm to 0.5 m. Again, the chalk beds are generally

homogeneous, lacking in any distinct internal structures.

Among the principal structural features of interest at this locality is a main fault of the Balcones system, its vein/gouge zone, and associated fractures. Unique to this northern portion of the outcrop trend are cross-faults, contained within grabens of the major Balcones system. These cross-faults have resulted in a keystone block geometry within the main graben which we have named a graben-in-graben structure. The final structural setting of interest is a small roll-over anticline in the hanging wall of a small displacement cross-fault. An increased fracture intensity is associated with this fold.

Two large displacement faults of the Balcones system are exposed in this quarry (Figure 26). One is a listric normal fault forming part of the main Balcones system graben, while the other is evidently a high-angle cross-fault. Both fault zones are filled by pyrite, clay, calcite

Figure 26. Graben-in-graben fault systems. a) Listric normal fault of the Balcones fault system forming part of a main graben structure. Fault zone is vein filled.

Figure 26. (continued). Graben-in-graben fault systems. b) Nested graben structure produced by small-displacement cross-faults. c) Close-up of lowest, keystone graben block in (b).

veins, analogous to the veins in faults from the San Antonio area. Numerous, small, spider-web veins are present in both hanging wall and footwall strata bounding these fault zones. Vein density is high within 0.5 m of each fault zone and then rapidly decreases. Fault zone veins contain rhombic, coarse-grained calcite, euhedral pyrite, and amorphous clay masses. Vuggy porosity is preserved in many of these veins. Slickensides are well developed on the fault zone and vein walls, with slip surfaces localized by vein clays. The main Balcones fault strikes N40W, and dips 63NE. Slickensides on this fault have a rake of 78° S. The oblique slip on this fault is probably a consequence of variability in displacement along strike. The large cross-fault strikes N34E, and dips 62NW. Slickensides indicate that displacement was directly down-dip for this fault zone. Although no decrease in fault dip is apparent in outcrop, rotation of hanging wall strata into the fault indicates a listric geometry for the cross-fault. This fault probablysoles into the Eagleford Shale which is approximately 10 m to 12 m below the level of exposure.

A series of nested grabens bounded by NE striking cross-faults, part of the graben-in-graben structure, are well exposed at the east end of the quarry (Figure 26). Fracture intensity for beds of comparable thickness is highest in the structurally lowest, most internal graben. Here at Waco, and for the northern portion of the outcrop trend in general, fracture intensity scales reasonably well with bed thickness, thinner beds are more highly fractured than thicker beds in the same structural position (Figure 27). This is a direct consequence of the increased thickness of intervening marl beds. Because of the thicker marls, individual chalk beds behave as independent mechanical units. A corollary of this is that most fractures here are bed contained, they die-out at marl interbeds. The only exception is adjacent to faults.

Three systematic fracture sets are present in these outcrops. As in San Antonio, vein filled extension fractures are the oldest fractures present. We suspect they did not form large through-going joints here because the thicker marl interbeds were effective barriers to widespread fluid infiltration from below. The almost exclusive coincidence of veins and faults here is strong qualitative support for this

Figure 27. Scan lines in nested graben structure. a) scan line in an 8 in thick chalk bed in the keystone block shown in Figure 26. b) scan line in a 23 in thick chalk bed directly below the bed in (a), separated by a 7 in thick marl.

interpretation. The other two fracture sets evidently formed during faulting. Each of the other fracture sets is represented by shear fractures synthetic to the major faults and a series of related vertical extension fractures. One set is parallel to the principal faults of the Balcones system and strikes N40°W. The other set is parallel with the cross-faults and has an average strike of N50°E. Shear fractures terminate against graben-bounding faults and are almost exclusively restricted to hanging walls. Most shear fractures are within 2 m of a fault. Extension fractures within 3 m of faults transect several beds and terminate against shear fractures or faults. At greater distance from fault zones the shear fractures terminate at bed boundaries. The graben-in-graben structure is shown schematically in Figure 28.

A map of a small portion of the quarry floor was made at a scale of 1:12 about 300 m from the graben-in-graben structure (Figure 29). The map shows similar features to those

HIGH-ANGLE, GRABEN-IN-GRABEN NORMAL FAULTS

Figure 28. Schematic illustration of the graben-in-graben structure.

described from scan-line data, although there are intriguing differences. Again, the distributions for length and spacing follow a negative exponential law. Also, there is a regularity in spacing among the longest fractures. However, the best developed fracture set and the longest fractures both trend north-south and the next best developed set trends east-west, with much scatter in the latter (Figure 30). Some important aspects of fractures in this map area are: (1) Few of the fractures display free ends (fracture tips); on average 25% of all fractures have a free end. The set that has the most is the N-S set, about one half having a free end. Other orientations are statistically more likely to abut against other fractures. Moreover, all but a few of the fractures on our map are traversed by others, whether their ends are free or not. The mean number of connections per fracture is about 6, although the frequency distribution is skewed toward low values with a high kurtosis. Nevertheless, the number of connections per unit length of fractures is nearly independent of orientation, whereas the most connections are found along fractures oriented N-S (Figure 30). Although we would judge this map area

to be highly conductive to fluids if all fractures were open, there would be a petroleum production advantage in intersecting as many N-S fractures as possible due to their increased permeability lengths. (2) There are numerous curved fracture segments, some traversing nearly a right angle bend from a N-S to E-W orientation. It was not possible to determine whether these curved segments represent two fractures of each set joining or whether their junction was a particularly persistent stress concentration from which two fractures propagated during two different fracturing events. It seems implausible, though not impossible, that a single fracture, during one episode of propagation, would traverse such a 90° bend.

A small roll-over anticline is present in the hanging wall of a small listric cross-fault on the west side of the main quarry (Figure 31). Extension fractures fan around this fold and show the highest intensity between the listric fault and crest of the structure (Figure 32). Continuing into the hanging wall away from the fault and crest of the fold the fracture intensity exponentially decreases. A group of relatively evenly-spaced shear fractures, sympathetic to the headwall segment of the fault, are present in the footwall within 5 m of the fault. As with the listric fault system in San Antonio, fracture intensity within the hanging wall is 1.5 times greater than for the footwall. The similarities in the principal features of the fracture systems between this listric fault system and the much larger system in San Antonio, their wide geographic separation, and the differences in stratigraphy, particularly the much thicker marl interbeds here in Waco, suggests that deformation style is scale independent. This implies that smaller structures may serve as accurate models for much larger, productive, subsurface structures.

Figure 29. Map of a portion of the quarry floor of the Lehigh Quarry, Waco. The mapping was done at a scale of 1:12. A large percentage of the fractures are curved and the preferred orientation of fractures is less than in San Antonio. Note that the mapped area is about one half that of figure 19.

Figure 30. Plots of data from the Lehigh Quarry map. a) Frequency plot of fracture orientation. Two moderately well developed fracture sets exist. b) Plot of length versus orientation. The best defined set (N-S) also harbors the longest fractures. c) Fracture connections (or intersections with other fractures) per foot of fracture length versus orientation. The average connections per foot do not show any particular trend with orientation. d) Number of connections versus orientation. See text.

Figure 31. Small roll-over anticline in the hanging wall of a listric cross-fault.

Figure 32. Scan line across the cross-fault and anticline shown in Figure 31. Arrow indicates the location of the cross-fault.

Lafarge Cement Quarry, Dallas

The Lafarge Cement Quarry is located at 3333 Fort Worth Avenue in Dallas. As with the other quarries, access is only by permission. Requests for entry should be directed to Mr. John S. Wittmayer, Environmental Manager, Lafarge Corporation, P.O. Box 324, Dallas, TX 75221. This quarry was abandoned in 1982. Consequently, the site is extensively overgrown. Due to a change in the style of quarrying from terraced levels to a layback system there are few walls to inspect here.

Approximately 15 m of the basal Atco Chalk Member are exposed in this quarry. The contact with the underlying Eagleford Shale is exposed at scattered locations throughout the pit, and the quarry floor is generally within 1 m of the contact. Chalk bed thickness is more variable here than at the other localities ranging from 30 cm to 4 m. Intervening marls also show a greater variability in thickness ranging from 4 cm to 1.5 m. In general, the marls are thicker here than elsewhere along the central Texas outcrop trend. Again, the chalk beds tend to be homogeneous, lacking any significant internal structure. An interesting stratigraphic oddity is a very high concentration of fossil shark teeth in the top 1 m of the Eagleford Shale.

As a consequence of abandonment and the change in quarrying techniques fractures and fault styles are much more difficult to observe now than when we originally worked in this quarry in 1981. Photographs from our earlier investigations (Figure 33) illustrate that the fault style here is analogous to that in Waco, graben-in-graben structures predominate. Because of less offset on the main faults and cross-faults of the Balcones system, and because of the increase in marl thickness, fracture intensities here are lower than in Waco (Corbett and others, 1987). Even near faults, the thicker marl beds effectively terminate most fractures.

Well exposed at this locality is a vein system captured by later faults (Figure 4). The superposition of faults and veins is particularly compelling because the two surfaces are nearly

orthogonal. The fault surfaces have very small displacements, generally only a few centimeters. They are also notably curvilinear, a consequence of being localized by the vein system which did not develop as a simple planar array.

Our quarry floor map (Figure 34) in the Lafarge quarry was made 150 m from faults shown in Figure 4. The fractures in this quarry are remarkable in their lack of preferred orientation, continuing the trend toward more random fracture fabrics from San Antonio, through Waco, to the present locality. Fractures length, spacing and number of connects per fracture show the same negative exponential distribution as in the other quarries. However, except for a moderately abundant N-S set and a moderately long ENE set, few systematics in either length or abundance with respect to orientation are apparent (Figure 35). As with Waco and San Antonio, we do not put much credence in surface-derived values of fracture aperture due to the age of the quarry. Again, similar to Waco, we are struck by the connectedness of the fracture system. On average only 25% or the fractures have a free end. There are 5.3 fracture intersections per fracture or about 4.6 per fracture foot (Figure 35). The abundance of curved fractures is greater in the Dallas quarry, perhaps also reflecting the absence of a strong preferred orientation. The fracture pattern, in map view, suggests a uniform extension in the plane of bedding under low differential stress. We would expect that the fracture system represented here would be highly conductive if all fractures are open and nondirectional. A horizontal well in any direction would do as well as any other, everything else being equal.

The other primary feature of interest at this site are oxidation halos around fractures in grey chalk which was originally below the water table (Figure 17). Since these have been extensively discussed in the previous section, we will simply reiterate that fractures, even vein-filled, tight ones, are obviously much more permeable than the chalk matrix.

Figure 33. Graben-in-graben fault systems. a) Main Balcones system fault indicated by an arrow truncates a cross-fault. b) Close-up of a cross-fault.

Atco Chalk, Lafarge Quarry,
Dallas Texas

1 ft
1 m

N

-46-

Figure 34. Map of a portion of the quarry floor of the LaFarge Quarry, near Dallas. The mapping was done at a scale of 1:24. The large percentage of curved fractures is similar to that found in Waco.

Figure 35. Plots of data from the LaFarge Quarry map. a) Frequency plot of fracture orientation. There is no particular preferred orientation to the fracturing. b) Plot of length versus orientation. c) Fracture connections (or intersections with other fractures) per foot of fracture length versus orientation. d) Number of connections versus orientation. See text for discussion.

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PREDICTING FRACTURE CONNECTIVITY AND INTENSITY WITHIN THE AUSTIN CHALK FROM OUTCROP FRACTURE MAPS AND SCANLINE DATA

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ABSTRACT

Maps at scales of 1:12 to 1:48 of portions of quarry floors and scanlines along vertical to near vertical outcrop faces in the Austin Chalk reveal the change in fracture intensity, connectivity, length, and ordering with respect to orientation along the trend from Del Rio to Dallas. Outcrops with more marl beds and/or a larger total percent smectite clay (Del Rio, Waco, Dallas) display, in general, more random, more closely spaced, and more interconnected fractures. Fractures in the vicinity of San Antonio where smectite clay content is low, by contrast, are, 1) developed into well oriented sets and, 2) more widely spaced, 3) longer and, 4) less interconnected than other areas studied. Several of the fracture patterns mapped indicate that the concept of "fracture set" has only local applicability in the Austin Chalk. Highly curved fractures outside of the San Antonio area and the occurrence of en passant fracture geometry suggest low differential stress at the time of fracturing. Random orientation of all but the longest fractures suggests uniform extension of the Austin Chalk in the horizontal (bedding) plane.

INTRODUCTION

Naturally fractured reservoirs represent an increasingly important target for petroleum exploration, especially with the advent of horizontal drilling. Optimum success in both exploration and production, however, depend on adequate characterization of the fracture system and associated rock mass permeability as a function of lithology (e.g. bed thickness, clay content, percent calcite), rock properties (e.g. triaxial compressive strength, porosity, permeability), structural position, and tectonic history. It is impossible to completely characterize fracture networks at depth. Geophysical and petrophysical methods at best yield measures of fracture spacing and aperture, but no information concerning the amount and degree of fracture interconnection or fracture dimensions. Yet fracture connectivity, especially, is crucial to reservoir response (see Long and Witherspoon, 1985).

A simple, thought experiment illustrates the kinds and importance of interconnectivity. Consider three different fracture networks (Fig. 1). Only relatively straight, long, and isolated fractures occur in the first fracture array (Fig. 1a), and as a result the degree of interconnectivity is poor. Depending on the distribution of fracture lengths and how many are intersected by a horizontal well bore, the success in petroleum production could range from good to poor. The fractures would act as fluid conduits, but due to low matrix permeability and possibly great differences in permeability between open fractures and matrix, fluid flow would short circuit through the fractures leaving large regions of the reservoir undrained. Similarly, water flooding would be inefficient, because the water would flow through the open fractures, by-passing mobile oil within

blocks between the isolated fractures. Although the dimensions of blocks across subtending fractures is small, the other, parallel-to-the-fracture direction, is large. For the second hypothetical fracture array there are two fracture sets distributed in a spatially heterogeneous fashion (Fig. 1b). Both sets on average have equal fracture spacing, but their mean lengths are different due to the poor development of the less abundant set. Drainage of this reservoir would be optimized by intersecting the patches where fractures are interconnected (such as in the left, optimized by intersecting the portion of this figure), but even then only a limited portion of the reservoir would be drained. The degree of fracture interconnection in places is high but spatially isolated. In the third situation, all fractures are connected (Fig. 1c). Whether the fractures are straight or curved, this situation leads to relatively smaller intact block sizes, higher hydraulic conductivity through the fractures if they are open, and therefore a highly conductive reservoir. In this case the direction of horizontal drilling is immaterial, whereas in the first case the choice of the horizontal drill orientation was critical. A consequence illustrated by these three situations is that prediction of both the degree of interconnectivity and the spatial variability of the interconnectivity, is important in understanding the success of draining a fractured, low matrix-permeability reservoir.

We have investigated the Austin Chalk outcrop trend from Dallas to Del Rio (Fig. 2) in order to quantify further the characteristics of fracturing, especially interconnectivity. The results reported here amplify and extend earlier studies on fracturing in the Austin Chalk (Corbett, 1982; Corbett *et al.*, 1987, 1991; Reaser and Collins, 1988). We provide new data on fracture length, connectivity, spacing, and areal density, and the significance of establishing these parameters for accurate reservoir characterization and modelling.

Understanding the fracturing in the Austin Chalk is a particularly timely topic given the current active exploration interest.

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Figure 1. Three types of fracture connectivity: a) No connection among fractures—optimum reservoir drainage is achieved by intersecting the most fractures possible by horizontally drilling normal to the fracture trend; b) Patchy connectivity—best drainage is achieved by drilling through patches of connected fractures; c) High connectivity—direction of drilling unimportant.

and drilling activity. Successful wells in the Austin Chalk have historically been those where zones of high fracture intensity and presumably zones of high fracture interconnectivity have been found. Production is thought to be predominantly structurally controlled. Although zones of increased fracture productivity are often near faults (e.g. Kuich, 1989), they also are associated with other structures (Stapp, 1977). Our data on the characteristics of fracturing in the Austin Chalk may bear on the occurrence of fractures in the Austin Chalk and the underlying reasons for the variability in production.

The plan of this paper is to, 1) review the regional geology and rock properties of the Austin Chalk, 2) describe the mapped fracture arrays, and 3) present data on the constituent fracture populations.

REGIONAL GEOLOGY

The regional geology, petrography, diagenesis and sedimentology of the Austin Chalk have been previously summarized (Corbett *et al.* 1987, and references therein). We give here only a brief review for the purposes of this paper. The Austin Chalk crops out from Oklahoma to the Mexican border, generally

Figure 2. Location map for study sites, after Corbett *et al.* (1987). Upper Cretaceous outcrop trend is shown stippled and subsurface structural contours on top of the Austin Chalk are dashed lines. Symbols: RGE, Rio Grande embayment; LFZ, Luling fault zone; BFS, Balcones fault system; M-TFZ, Mexico-Talco fault zones; ETE, East Texas embayment. Numbers refer to study locations: 1) Tequequite Creek; 2) Uvalde (not reported on in this paper); 3, 4) Quarries in San Antonio, only one of which (Old Alamo Cement Quarry) was mapped; 5), Waco; 6) Dallas.

trending parallel to the form of the Gulf Coast Basin. Along this trend, the Austin Chalk consists of fine-grained carbonates and marls derived from pelagic muds. Typical fossil fragments include coccoliths, planktonic and benthic foraminifera, calcispheres, mollusks, echinoids, and bryozoans. Porosities in outcrop range from 30% in the vicinity of Dallas, decreasing southwestwardly to 9% at Langtry (Cloud 1975). Subsurface porosities are less than those found in outcrop (Dravis, 1979). Subsurface matrix permeabilities average less than 0.1 md in the (Snyder and Craft, 1977).

The stratigraphy of the Austin Chalk is shown in Figure 3, after Corbett *et al.* (1987). Our data from Dallas, Waco, and San Antonio quarries comes from the Atco Chalk member, and the Tequesquite Creek data near Del Rio comes from the Dessau member of the Austin Chalk. Deposition of the Chalk between San Antonio and Austin occurred on a pre-existing high (San Marcos Arch) (Fig. 2). Bedding is massive, marl interbeds are not prominent, and the total stratigraphic thickness is reduced in this vicinity. To the southwest and northeast, rhythmic bedding appears with marls becoming a large portion of the stratigraphic section (Dravis, 1979). The thickness of the chalk in outcrop varies from a few hundred feet to about 600 feet (about 180 m) (Pessagno, 1969). The thickness generally increases down dip away from the San Marcos Arch reaching a maximum of about 1000 feet (about 300 m) in the Kanes trough in Gonzales and Wilson counties (Holifield, 1982).

Figure 3. Lithostratigraphic correlation of units of the Austin Chalk, after Corbett *et al.* (1987). Maps reported on in this paper were made in the shaded units.

The structural setting of the Austin Chalk has been controlled by the Gulf Coast Basin and affected by the Balcones, Luling, Mexia, and Talco fault zones as well as old, inherited, Ouachita fold and thrust belt trends (Weeks, 1945). The major faulting style in outcrop gives rise to horsts and grabens with conjugate normal faults, often listric, dipping to the southeast and northwest (Corbett *et al.*, 1987, 1991). In the Waco and Dallas areas, graben-within-graben structures prevail (Ibid). Movement on all these faults may have begun as early as Late Cretaceous, although Weeks (1945) reports that major movement occurred along all fault zones during the late Oligocene or early Miocene. Kuich (1989) found that major motion on faults in the Giddings Field of Burleson and Grimes counties was in the Eocene. There is no evidence for a spatial trend in ages as would be expected from fault propagation. Likewise, there is no evidence for episodic fault motion.

DATA COLLECTION PROCEDURES

Maps

Suitable sections of a quarry floor were located and cleaned and a map scale selected (1:12, 1:24, or 1:48). Sites were chosen on the basis of completeness of initial exposure and the ability to clean off rubble to expose nearly 100% of a bed surface. Excavation equipment was not used (compare Barton and Hsieh, 1989). Mapping was facilitated by using a gridded mapping square, 4 ft on a side, divided internally by 1 ft marker strings. Depending upon ultimate map size, a base line was established where necessary and the map square moved parallel to this surveyed reference line as mapping progressed. All fractures that could be observed from standing height (about 6 ft or 2m) were mapped. Mineralization and alteration along fractures were noted on the map.

Field maps were compiled and redrafted in this office to both facilitate data collection and allow comparison with our scanline data from vertical quarry faces (Corbett *et al.* 1991; see below). Lines were drawn on the maps parallel and normal to the major fracture sets and, in some cases, also oblique to the two most prominent fracture sets in order to sample the fracture networks. A fracture which intersected a sampling line was logged as to length, orientation, number of intersections with other fractures (connections), number of free ends, number of ends where the fracture abutted against another fracture, and fracture spacing. Fracture spacing was measured by drawing a perpendicular line from the fracture being logged to the nearest fracture of any orientation in a forward direction. Data on spacing of "sets" were also collected. We did not measure fracture aperture believing this number to be unreliable in surface outcrops (compare Barton and Hsieh, 1989).

Several decisions had to be made during the data collection process in the office. Many of the fractures on our maps, especially in regions away from San Antonio, are highly curved. As a consequence, we developed the following protocols for establishing the parameters outlined above. 1) If the bend in the fracture took place over less than 2 inches (5 cm), we considered the fracture to be composed of two separate segments. 2) Otherwise the fracture must have either ended or clearly abutted against another in a "T" intersection for fracture termination to be recorded.

Scanlines

We also measured fracture characteristics along scanlines placed on individual beds exposed on vertical to near vertical outcrops. Fractures intersecting the scanline were logged as to length, orientation and spacing. Because these data were collected in the same localities as the quarry floor maps, they provide a view of the third dimension. Scanline data is available for three of our four mapped sites: San Antonio, Waco and Dallas.

Limitations of the Data

Because our maps were made on two dimensional surfaces the data extracted from them is limited in several ways. First the map data provide no information in the third dimension of the length, shape, consistency of orientation or interaction with bedding surfaces of the fractures. Similarly, we cannot precisely how the fracture features measured at the surface can be extrapolated into the subsurface based on map data alone. For instance, how many of the fractures seen at the surface-form there? One indication that not *all* fractures are near-surface features is the fact that several fracture sets are locally unfilled; these fractures, at least, were formed in the subsurface and presumably therefore reflect conditions there. Another limitation is that the maps are of finite size. The longer fractures do not end on our maps so that there is a truncation bias in length for long fractures. In a similar way, fractures that could not be seen from standing height were not mapped. As a result there is a non-representative bias for small length

While the lack of accurate length for the longest fractures may be troublesome, smaller fractures are often unconnected to others and therefore of limited importance hydrologically (Segall and Pollard, 1983). A third limitation of our data is that it is based in maps which represent a miniscule proportion of the outcrop trend of the Austin Chalk. The largest map is 792 ft² (88m²). Yet, despite these problems, map data provide views of both fracture connectivity and shape unavailable by other means.

Scanline data, if used with map data, provide a view of the third dimension. However, although rapidly collected, scanline data do not provide information on connectivity where both the fractures and exposures are nearly bed-perpendicular. Fracture measurements along scanlines also have the representativeness uncertainty associated with the map data. However, because, 1) many more fractures can be measured in the same amount of time as it takes to map a representative fracture pavement and, 2) vertical outcrops in our areas are large, the same areal restrictions for maps do not apply to scanlines; longer fractures could be sampled. Maps and scanline data are complementary.

DESCRIPTION OF FRACTURE PATTERNS

Tequesquite Creek

We have made fracture maps along Tequesquite Creek, Texas, about 30 miles southeast of Del Rio on Route 277 (No. 1 on Fig. 2; Fig. 4). The map reported on here was made at a scale of 1:24 in the Dessau Chalk member. There are no surface faults mapped in the vicinity of the stream cut (Fig. 4). The area mapped lies on the north limb of a small anticline (Corbett *et al.*, 1991).

The fracturing in Tequesquite Creek is markedly different from any other which we have observed along the trend (Fig. 5). The fracture pattern is characterized by a set of long continuous widely spaced fractures of a persistent orientation between which are curved, nearly randomly oriented fractures; the latter appear much like mud cracks. The largest fractures, which generally trend N50E, are subparallel to the southwestern extension of the Balcones fault zone and are parallel to axis of the small anticline (Figs. 2, 6a). Another more abundant group trends N30W (Fig. 6b). Like other fracture patterns we see along the Austin Chalk trend, there are few fracture tips exposed. Only 15% of the fractures show tips, the rest being abutments against other fractures. The frequency distributions of the lengths of fractures in either group follow a negative exponential distribution as is found for the lengths (and spacings) of fractures throughout the Austin Chalk (Corbett *et al.*, 1991) and in most other studies of fracture pavements (e.g., Segall and Pollard, 1983; La Pointe and Hudson, 1985; Barton and Larsen, 1985; Barton and Hsieh, 1989). The number of fracture intersections or connections per foot of fracture length are nearly independent of orientation (Fig. 6c). On average,

Figure 4. Geology in the vicinity of the Tequesquite Creek study area, simplified from the Del Rio and Crystal City-Eagle Pass sheets, Geologic Atlas of Texas (Barnes, 1977,1976).

fractures display five intersections per foot of fracture length. Fracture spacing is distributed in a negative exponential fashion with truncation at the low end (Fig. 7a). As mentioned before, this truncation is due to the fact that fractures not visible from standing height were not mapped. There is no preferred orientation to fracture spacing at Tequesquite Creek (Fig. 7b) i.e., the spacing of fractures versus orientation show no trends on this map, despite the fact that the longest fractures appear to show a regular spacing. Apparently the great majority of fractures are nearly randomly oriented so that the few, albeit long, fractures which are regularly spaced, are a small portion of the population.

The northeast trending set has a mean length of 1.6 ft (0.5 m), whereas the less persistent but more prevalent northwest set has a mean length of about 1.2 ft (0.4 m). This illustrates the fact that the prominent, and apparently longest set, consists of closely spaced and parallel yet multiple fractures.

The two distinct fracturing styles on this map suggests a distinct fracturing mechanism for each. Our current hypothesis is that the long, straight, widely spaced joints occurred early due to local tectonism. The curved, nearly randomly oriented, fracture between the long straight segments occurred second by uniform stretching of the Austin Chalk along the crest of the fold as plunge developed. The evidence for this sequence is that curved fractures abut against the long, straight ones.

Although no data are available at this locality, elsewhere, such as at our Dallas site (see below) the curved, randomly oriented fractures appear to be bedding normal and therefore are not classic "syneresis" cracks (Nelson, 1985).

Figure 5. Fracture map along Tequesquite Creek. Stippled areas are fossils; blank areas are covered. See text for further discussion.

We predict that this fracture system would be highly conductive in the subsurface if, 1) present in substantially the same form as seen in outcrop and, 2) if all fractures are open as well.

Old Alamo Cement Quarry, San Antonio

We have made a map at a scale of 1:24 of a portion of the floor of the Old Alamo Cement quarry, in the Alamo Heights

Figure 6. Data plots from map shown in Figure 5. Data were collected along sampling lines as described in the text. a) Fracture length vs orientation; fractures trending N50-60E are longest; b) Histogram of fracture orientation azimuth, 0=north; the most abundant fracture trends are about N60E and N30W; c). Intersections with other fractures (connections) per foot of fracture length versus orientation of the fracture; fracture connectivity is nearly randomly distributed with orientation.

Figure 7. Plots of fracture spacing for the map shown in Figure 5. a) The frequency of fracture spacing closely follows a negative exponential distribution, as has been found for fracture length (Corbett *et al.*, 1991); b) Fracture spacing is nearly randomly distributed with respect to fracture orientation.

portion of San Antonio (No. 3 on Fig. 8). The mapped interval is about 13 ft (4 m) above the Austin Chalk-Eagleford Shale contact. Numerous normal faults, generally trending northeast, crop out near our study site. The local structure in the quarry is characterized by listric normal faults (Corbett *et al.*, 1991).

Fracturing in the vicinity of San Antonio (Fig. 9) is markedly different from that near Del Rio (Fig. 9). The most remarkable aspect of the fractures in this quarry at this level of exposure is the lack of intersections among fractures. The fracture network is characterized by a strong fracture preferred orientation, or relatively less dispersion in fracture orientation than elsewhere along the outcrop trend (Fig. 10a,b). There is essentially only one fracture set trending N45E, although a few long fractures trend N45W. The longest fractures, as at Tequesquite Creek, are in fact fracture zones. Although the longest fracture zone is more than 30 ft (9.1 m) long, the longest fracture is only about

- Kknm: Navarro Group-Marlbrough Marl
- Kpg: Pecan Gap Chalk
- Kau: Austin Chalk
- Kbu: Buda Limestone
- Qt: Edwards Limestone

Figure 8. Geology in the vicinity of the San Antonio study areas, simplified from the San Antonio Sheet, Geologic Atlas of Texas Barnes (1974). OA: Old Alamo Cement Quarry.

9 ft (2.7 m). The mean fracture length in this map is 1.1 ft (0.3 m). Due in part to the good preferred orientation, on average, the fractures on this map display only two connections per fracture, or 1.4 on a per foot of fracture basis (Fig. 10c). In addition, there is a greater proportion of unconnected fractures (*i.e.*, fractures with ends completely unconnected to other fractures as viewed in two dimensions) than in other study sites. Similarly, of those that are not totally blind, nearly 90% have a free end, or fracture tip, unconnected to other fractures; only 7% abut other cracks at either end. This connectivity is directional because there is a high preferred orientation of the fractures (Fig. 10b). However, because a significant portion of

the fractures are partially filled with vein minerals, the directional hydraulic conductivity is complex. As in all other sites, the fracture spacing is skewed toward small spacings (Fig. 11a), following the fracture length distribution that we have reported on elsewhere (Corbett *et al.*, 1991).

The most closely spaced fractures trend N45E (Fig. 11). There would be an exploration benefit to drilling normal to the best developed fracture set, especially higher up in the Austin Chalk member where the degree of veining apparently increases (Corbett *et al.*, 1991).

Lehigh Cement Quarry, Waco

A map of a small portion of the floor of the Lehigh Cement Quarry was made at a scale of 1:12. The particular locality mapped is about 10 ft (3 m) stratigraphically above the base of the Chalk. An unusual aspect of the regional geology is the occurrence of small north-south trending normal faults north of the quarry (Fig. 12). The local structure in the quarry is graben-in-graben structure (Corbett *et al.*, 1991).

Waco lies between our San Antonio and Dallas sites in ordering of the fracture pattern, San Antonio being the most ordered and Dallas the least. The best developed fracture set containing the longest fracture trends nearly north-south, the next best developed set trends east-west, but with greater scatter in orientation (Figs. 13, 14a,b). The longest fracture on our map is 8.3 ft (2.5 m) long; the mean for all fractures is 1.1 ft (0.3 m).

All but a few of the fractures on our map are intersected by others. The mean number of connections per fracture is about

six, although the frequency distribution is skewed toward low values with a high kurtosis. Moreover, the number of connections per unit length of fractures is nearly independent of orientation (Fig. 14c). Eleven percent of the fractures display free ends (fracture tips). The N-S fracture set has the most with about 50% of the fractures exhibiting a free end. Fracture spacing, though not randomly distributed, does not show a strong association with fracture orientation (Fig. 15). Like Tequesquite Creek, there are numerous curved fracture segments in the Waco site, some nearly curving through a right angle bend from a N-S to E-W orientation.

These curved segments may represent either two fractures of each set which joined, or fractures formed at a particularly persistent stress concentration during two different fracturing episodes. It seems implausible, though not impossible, that a single fracture would traverse such a 90° bend, during one episode of applied differential stress where the stress axes are fixed. However, if the greatest and least principal stresses were nearly bed parallel and nearly the same value, changes in the amount of one or the other could change the direction of the

Figure 9. Fracture map in the Old Alamo Cement Quarry, San Antonio. Cross-hatched fractures are vein filled. See text for further discussion.

Figure 10. Data plots from map shown in Figure 9. Data were collected along sampling lines as described in the text. a) Fracture length vs orientation of the fracture; fractures trending N45E and N45W are longest; b) Histogram of fracture orientation azimuth, 0=north; the most abundant fractures trend N40E; in addition, the dispersion in fracture orientation is low, i.e., there is a strong preferred orientation; c) Intersections with other fractures (connections) per foot of fracture length versus orientation of the fracture; fracture connectivity is, in general, low (compare figs. 6, 14 and 18).

Figure 11. Plots of fracture spacing for the map shown in Figure 9. a) The frequency of fracture spacing follows a negative exponential distribution, as has been found for fracture length (Corbett *et al.*, 1991); b) Fracture spacing vs fracture orientation. See text for discussion.

maximum principal compressive stress to change marked with time. This, too, would result in curved, single fracture

Although we would judge this map area to be highly conducive to fluids if all fractures were open, there would be an advantage for petroleum production in intersecting as many N-S fractures as possible due to their increased lengths.

LaFarge Cement Quarry, Dallas

The LaFarge Quarry in Dallas, Texas, was mapped at a scale of 1:24 in an area with few regional outcropping faults (Fig. 16).

The fracturing is less regular than that found in the Wafer Quarry (Fig. 17). Stretching the definition of a fracture set, we can recognize a poorly developed fracture set trending roughly north-south and a poor second set trending east-northeast (Fig. 18a, b). The most prevalent set is that which trends near north-south, although the set which has fractures of the greatest length is east-northeast, or parallel to the Gulf Coast Basin edge (Fig. 18b). The mean length of the east-northeast trending

Figure 12. Geology in the vicinity of the Waco study site, simplified from the Waco Sheet, Geologic Atlas of Texas, Barnes (1990). Note north-south faults north of the quarry studied.

fractures (set 1) is 1.6 ft (0.5 m) on this map, whereas the mean length of the north-southeast, (set 2) is 1.4 ft (0.4m). The most prevalent set of fractures, the north-south set (set 2), has a mean fracture length of 1.1 ft (0.3 m) on the map. There is no preferred orientation to the connectivity vs. orientation plot (Fig. 18c). Like the Waco map, few (13%) Dallas fractures show fracture tips; there are few free, unconnected fractures. There is no appreciable difference among the three fracture sets in their spacing (mean = ~0.3 ft) (Fig. 19).

The disorder in the fracture pattern in the Dallas Quarry are shown by, 1) zones of en echelon fracturing as exemplified by the en echelon fracture zone in the bottom middle of the map; 2) "fracture" fans such as shown in the lower right of the map;

like the Waco map, many of the fractures turn from one orientation to another through nearly 90°.

COMPARISON WITH SCANLINE DATA

The scanline data show similar negative exponential distributions for fracture spacing as found from the map data (Fig. 20; no scanline data are available from Tequesquite Creek). Most fractures measured along scan lines are more closely spaced than one foot. Also like the map data, fractures measured along scanlines are longest at San Antonio, although the longest individual fracture was a quarry wall face at our Waco study site (Fig. 21c). The scanline data, likewise, displays the same degree of preferred orientation as found among map sites. The fracture pattern from the Old Alamo Cement Quarry, San Antonio, shows the strongest preferred orientation (about N45E) and the LaFarge Cement Quarry, Dallas, the least. The degree of similarity in kind if not degree between the results from maps and scanlines, 1) mutually reinforce the conclusions drawn from both and, 2) provide additional confidence in extrapolating into the subsurface length and spacing patterns observed on the maps.

Figure 13. Fracture map in the Lehigh Cement Quarry, Waco. See text for discussion.

Figure 14. Data plots from map shown in Figure 13. Data were collected along sampling lines as described in the text. a) Fracture length vs orientation of the fracture; fractures trending North-South and perhaps East-West are longest; b) Histogram of fracture orientation azimuth, 0 = north; the most abundant fractures trend at about North-South and East-West; c) Intersections with other fractures (connections) per foot of fracture length versus orientation of the fracture; fracture connectivity is, in general, high.

Figure 15. Plots of fracture spacing for the map shown in Figure 13. a) The frequency of fracture spacing follows a negative exponential distribution, as has been found for fracture length (Corbett *et al.*, 1991); b) Fracture spacing: spacing is greater among North-South and East-West fractures. See text for discussion.

- Kau: Austin Chalk
- Kef: Eagle Ford Formation
- Kwb: Woodbine Formation

Figure 16. Geology in the vicinity of the Dallas study site, simplified from the Dallas Sheet, Geologic Atlas of Texas, Barnes (1972). The west boundary of the quarry is marked on the map (quarry symbol at LA); the quarry extends to the east into the Austin Chalk, where the map of Figure 17 was made.

Figure 17. Fracture map in the LaFarge Cement Quarry, Dallas. See text for discussion.

Figure 18. Data plots from map shown in Figure 17. Data were collected along sampling lines as described in the text. a) Fracture length vs orientation of the fracture; there is no strong pattern to fracture length; b) Histogram of fracture orientation azimuth 0=north; there is no strong pattern to preferred orientation of fractures; c) Intersections with other fractures (connections) per foot of fracture length versus orientation of the fracture; fracture connectivity is, in general, high.

Figure 19. Plots of fracture spacing for the map shown in Figure 17. a) The frequency of fracture spacing follows a negative exponential distribution, as has been found for fracture length (Corbett *et al.*, 1991); b) Fracture spacing. Spacing is small and not preferentially oriented. See text for discussion.

Figure 20. Plots of fracture spacing from scanline surveys. Individual pairs of each histogram bar represent contributions from each scanline; scanlines are indicated in the legend by numbers in parentheses. Arrows point to values on the horizontal axes for the thickness of the beds along which each particular scanline (parenthetical numbers) was made.

Figure 21. Plots of fracture length versus orientation from scanline surveys. The legend matches plot symbols with particular scanline surveys (parenthetical numbers). Arrows point to the orientations of each scanline (parenthetical numbers). The trend of the nearest segment of the Balcones fault is indicated as "Local Fault Trend".

DISCUSSION AND CONCLUSIONS

Fracture spacing, a fundamental control on interconnectivity, is thought to be a function of rock strength and brittleness. Factors that control strength and brittleness are composition, grain size, porosity, bed thickness and tectonic history. Rocks composed primarily of more brittle constituents such as dolomite, quartz, and feldspar have higher fracture intensities (e.g., Nelson, 1985, Fig. 4-4). Rock strength increases with decreasing porosity as has been shown by Price (1966), Dunn *et al.* (1973), and for the Austin Chalk, by Corbett *et al.* (1987). Corbett *et al.* (1987) show that, in addition to porosity, ultimate strength correlates with the smectite clay content. Brace (1961), Ramez and Mosalamy (1969) among many others show that increased compressive strength correlates with decreasing grain size. Perhaps the best studied relationship between fracture spacing and a lithologic property is that of bed thickness. (Bogdanov, 1947; Harris *et al.*, 1960; Price, 1966; Sowers, 1972; Ladiera and Price, 1981). Sowers (1972) show that the relationship between fracture intensity and bed thickness can be explained by an interfacial instability between beds giving rise to a regular spacing in stress concentrations. This instability arises due to different elastic properties among beds.

Two other factors must be considered in understanding fracture intensity. One is that some rocks over geological time periods may deform by other processes. For instance, carbonates which contain greater than about 15% clay may deform by pressure solution at a differential stress lower than that for brittle failure (e.g., Marshak and Engelder, 1985). Likewise, it is conceivable that rocks of extremely uniform character may have few stress concentrations at which fractures can initiate. Therefore, one would expect, everything else being equal, that the rocks which are heterogeneous should be more highly fractured. This, in part, is the reason why porosity and smectite clay content control strength, in that higher porosities and larger smectite clay content reflect a greater number flaws or stress concentrations (Pollard and Aydin, 1988). Clearly a number of factors control fracture abundance in rock, e.g., bedding thickness, structural position and proximity to faults, and intrinsic properties that control rock strength such as porosity, grain size, clay content, etc.

Both porosity and clay content of the chalk in the San Antonio (Old Alamo) quarry are relatively high with respect to

other areas along the outcrop trend and the rocks are among the weakest and most ductile (Corbett *et al.*, 1987). In fact, this study site has the lowest fracture spacing and lowest area density of fracture intersections of all areas studied (Table 1). This correlates with observations of fractures at the Tetori Anticline, NW Montana (Sinclair, 1980) where weaker more ductile lithofacies in the Mississippi Madison Group exhibit more ordered fracture orientations and fracture spacing. Corbett *et al.* (1987) have found that rocks from Tequesquite Creek have the greatest ultimate strength, lowest porosity, and highest smectite clay content of those areas we have studied. As a result, fracture intensity and number of intersections there are on average higher. The ultimate/fracture strength of the Austin Chalk for samples from Waco ranges from 38.5 MPa ($P_c = 10$ MPa) to 103 MPa ($P_c = 70$ MPa) (Wiltchko, unpublished data), i.e., about the same, or somewhat weaker than at San Antonio. Accordingly, we anticipated behavior similar to that at San Antonio, everything else being equal. However, these two areas are very different in their fracture patterns and intensities, suggesting that factors such as bed thickness and structural position complicate the simple, laboratory strength-intensity relationship. The low strengths for the laboratory samples from our Dallas site are likewise inconsistent with the high intensity of fracturing on our map from there. However, the Dallas map site is on the bed forming the contact with the underlying Eagleford shale and consequently it may be more highly fractured due to the proximity to overpressure fluids (Corbett *et al.*, 1991).

As our data show, fracture spacing in the sense of regular fracture sets or arrays, appears to have limited application in some areas within the Austin Chalk, especially near Del Rio and Dallas. We find that fracture spacing in the Austin Chalk follows a negative exponential distribution when one measures the distance between fractures of any orientation along either map sampling line or a scanline. One can somewhat artificially identify fracture sets, as we have done, and measure the fracture spacings, ignoring intervening ones. However, this measure ignores the bulk fracture density. Therefore, for units as fractured as the Austin Chalk, and for units lacking, in general, a strong preferred orientation of fracturing as in the Austin Chalk, other measures of fracture intensity such as fracture line lengths per area (Table 1), or fractal measures (Mandelbrot, 1983; La Pointe, 1988) are more appropriate. In these measures, therefore, that one would correlate with rock

Table 1

Map	Mapped Scale	Local Balcones Fault Trend	Ft Above Base of Chalk	Strength (MPa)	Total Map Area (Sq. Ft)	Total # Fracture Intersections	Intersections/ Area	Total Fracture Line Length (ft)	Fracture Length/ Area	# of Free Ends	Free Ends/ Area	Austin Chalk Member
Tequesquite Cr	1:24	100	?	168	537.00	1834	3.42	821.00	1.53	94	0.18	Dessau Chalk
San Antonio	1:48	40	13	48	953.00	80	0.08	191.00	0.20	292	0.31	Austin Chalk
Waco	1:12	20	9	41	179.00	752.5	4.20	286.00	1.60	67	0.37	Austin Chalk
Dallas	1:24	10	0.5	51	382.00	1039	2.72	539.00	1.41	106	0.28	Austin Chalk

See note 1

1: Strength at 34 MPa confining pressure and about 2 % strain. Data from Corbett and others (1987) except for Waco, which is from Wiltchko (unpublished data).

strength, composition, bed thickness, and tectonic history in order to produce a predictive tool.

Although it is impossible to clearly separate all of the factors contributing to fracture intensity and style in the Austin Chalk, several observations seem appropriate.

1) The Atco Chalk member in the vicinity of San Antonio is massively bedded (free of marl interbeds). There, too, the fractures are least interconnected and most ordered with respect to orientation.

2) The percent of intercalated marl beds in the portion of the Austin Chalk we studied increases from San Antonio toward both Dallas and Del Rio as does the degree of development of curved, nearly randomly oriented small fractures between major fracture sets.

3) Several modes of origin for the curved, "chicken wire" or mudcrack pattern of fracturing best developed in Dallas and Del Rio are possible. Curved fractures are generally indicative of a low differential stress (e.g., Olson and Pollard, 1989). We have suggested that the curved fractures are due to uniform stretching in the plane of bedding. Others have proposed the chalk is "self sourcing," whereby maturation of solid organic matter in the chalk beds leads to the evolution of liquids and gas of higher volume, cracking the chalk (Grabowski, 1981, 1984; Hunt and McNichol, 1984; Hinds and Berg, 1990). The loss of volume due to expulsion of hydrocarbons would lead to uniform shrinking, producing the same end result as stretching. Without further paleostress and stress measurements, it is impossible to identify where each mechanism applies.

4) With the exception of Waco, the longest fractures trend parallel to the Gulf Coast Basin edge, suggesting the dominant control on the fracturing was the basin configuration.

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An Approach to Exploration for Naturally Fractured Reservoirs

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ABSTRACT

The ability to drill horizontally through fractured rocks of otherwise tight oil and gas reservoirs has stimulated renewed interest in naturally fractured reservoirs worldwide. Principal targets in the United States include the Austin Chalk, Bakken Shale, Cane Creek Shale, Mesaverde tight gas sandstones, Niobrara Limestone, and the Permo-Triassic clastics of Prudhoe Bay. Essential is the prediction of 1.) local and regional structure, 2.) orientations of the fractures within the structural framework, 3.) fracture spacing (density), length, width and connectivity, and 4.) stratigraphic location within the target formation where the rocks are apt to be most fractured. Items 1 and 2 are important for intersecting an optimum number of the best developed fractures. Item 3 allows evaluation of potential well productivity and economics. Item 4 is important because horizontal boreholes can be targeted to 20-ft. (6.2 m) stratigraphic intervals and the fracture susceptibility of rocks can change with subtle variations in porosity, grain size, mineralogy, bedding thickness, and pore fluid pressure, among other factors.

In this paper we integrate data and concepts dealing with 1.) orientation of fractures in local structures, 2.) fracture spacing, length and connectivity in outcrop, 3.) problems associated with extrapolation of outcrop data into the subsurface, 4.) factors that control fracture in rock and the structural stratigraphy, and 5.) inferences concerning oil maturation, migration and trap and seal formation, in order to outline a generic approach for the exploration of naturally fractured petroleum reservoirs.

INTRODUCTION

During the last few years the technology for drilling horizontal boreholes has swept the petroleum industry and made possible new or revitalized oil plays in a number of states. Examples include Texas (Austin Chalk), Montana and North Dakota (Bakken Shale), Alaska (Prudhoe Bay, Permo-Triassic clastics), Utah (Cane Creek Shale, Permo-Triassic clastics) and Colorado (Niobrara Limestone, and Mesaverde tight gas sandstones). In fact, the annual growth rate of horizontal drilling is nearly 300% in the U.S. and close to 250% world wide (Fritz et al., 1991, p. 10). Perhaps the most spectacular results have been experienced in the Austin Chalk trend (Fig. 1) where, as of September 1990, 261 horizontal boreholes had been drilled with productivities up to 5 times that of vertical wells and with initial potentials of as much as 5,500 bbl (875 m³/day) (Fritz et al., 1991, p. 26, 33).

A main purpose of horizontal drilling so far has been to intersect primarily bed-perpendicular natural fracture systems in which hydrocarbons abide. That is, in nearly flat-lying strata the fractures are vertical and are poorly sampled by conventional vertical boreholes. The chances of intersecting such fractures with a horizontal borehole are vastly greater, especially since it is now possible to control the azimuth and depth of the horizontal segment of the borehole so as to target beds within a 20-ft. (6.2 m) interval.

Figure 1. Location map of southeastern Texas showing outcrop trend of Austin Chalk and sample locations (numbered dots). BFS = Balcones Fault Zone, LFZ = Luling Fault Zone, M-TFZ = Mexia-Talco Fault Zone, ETE = East Texas Embayment, RGE = Rio Grande Embayment. Structure contoured (C.L. = 5,000 ft., or 1,524 m) on top of Austin Chalk. From Wiltschko et al. (1991). Point 1 is 30 mi. (48 km) south of Del Rio, Texas on Rt. 277.

It follows that essential elements that must be considered for a successful horizontal well in formations such as the Austin Chalk include: 1.) stress history that produced the fractures, whether due solely to burial and uplift or to superposed tectonic processes that caused folding and/or faulting, 2.) orientation of the best developed fracture sets relative to local and regional structure so that the horizontal borehole can be directed perpendicular to the best developed fracture set, 3.) fracture spacing (density), 4.) fracture width, length, height, degree of bed-containment and connectivity, 5.) fracture permeability and permeability change with effective stress, which when combined with items 2 to 4, can serve as the basis for predicting productivity of fracture systems, 6.) stratigraphic intervals within the formation that are apt to be the most fractured, i.e. the structural stratigraphy, and 7.) timing and location of petroleum maturation and migration and trap/seal formation.

Item 1 will not be discussed further. Determination of the current in situ stresses, their relationship to the paleostresses in the rocks at the time of fracturing, the relations between stresses and structures such as folds and faults and the development of fractures genetically related to the folds and faults are topics central to structural geology itself and about which much has been written (e.g., Price, 1966; Stearns and Friedman, 1972; Nelson, 1985). As such they are beyond the scope of this short paper.

We do have data from our ongoing investigation of the Austin Chalk that relate to most of the other items in the above list. Item 2 requires outcrop studies of fractures on structures also likely to occur in the subsurface. Items 3 and 4 require making pertinent measurements in outcrops and extrapolating these data into the subsurface. Item 5 requires observation of fracture fillings and/or experiments to determine the degree of fracture closing and corresponding decrease in permeability as a function of effective pressure. Item 6 requires that the factors important in controlling fracture in rock and the physical environment at the time of fracturing in the subsurface be identified. Such an effort leads to the identification of the most brittle (fractured) facies within the target formation, i.e., the structural stratigraphy. For Item 7, it is essential to establish the relationships between petroleum maturation and migration and fracture development.

The purposes of this paper are: 1.) to discuss briefly the important factors involved in making a prediction of natural fracture development; 2.) to bring into focus data already collected and that are planned for the Austin Chalk, and 3.) from these components to put together a generic approach for the exploration of naturally fractured reservoirs based on theory, experimentation, and lab, field and subsurface observations.

OUTCROP FRACTURE DATA

We have collected outcrop data on fracture develop-

ment in the Austin Chalk from just east of Del Rio through Uvalde, San Antonio and Waco to Dallas, Texas. Corbett et al. (1991a, b) mapped the major fractures developed in four structural types found in both outcrop and in the subsurface (Fig. 2). These structural types include fractures related to anticlinal folds (Stearns and Friedman, 1972; Nelson, 1985, p. 14-17), monoclinial flexures, listric normal faults, and graben-in-graben normal faults. Accordingly, fairly good understanding has been developed of the orientation of the best fracture sets relative to local and regional structure and also of the size of the fractured zone within the fold or adjacent to the fault (i.e., the fracture halo).

Figure 2. Schematic illustrations of four structures and their associated fractures, as found in outcrop along the Austin Chalk trend.

Discussions of these data with operators in the Austin Chalk trend reveal that the size and complexity of the outcrop structures are about the same as those shown on seismic sections through Austin Chalk prospects. Fracture geometries are documented with field measurements and photographs (Corbett et al., 1991a). In addition, our observations indicate that: 1.) the hanging walls of normal faults are more highly fractured than adjacent footwalls, 2.) the inflection zones of monoclinial flexures are highly fractured, and 3.) the fractures are largely contained within chalk members, even in fault zones, where the chalk beds are separated by marl/shale beds thicker than 4 in. (10 cm). Accordingly, there is a reasonable conceptual model for the development and geometry of fractures on local structures with which to plan borehole trajectories.

Regional fractures due to the burial of the beds also are probably developed (Price, 1974; Narr and Currie, 1982),

Figure 3. Example of detailed map of fracture traces on bedding plane in the Atco Member of the Austin Chalk at the Lehigh Quarry, Waco, Texas (Location 5 on Fig. 1). From Wiltchko et al., (1991).

well as those related to the local development of high pressures, i.e., self-hydrofractures or expulsion fractures, discussed below. The orientation of the regional fractures would be the same as that for some of the struc-

ture-related fracture sets as the regional extension perpendicular to the Cretaceous strand line would have exerted a control on both regional and local fracture development, i.e., the orientations of the local and regional least compressive principal stresses are the same. Regional fractures alone would have to be studied outside the fracture halo about local faults and folds.

Figure 4a. Fracture-spacing data from fourteen scan lines defined at four localities sampled by Corbett et al. (1991a). The scan lines are placed on vertical outcrops of the Austin Chalk and run parallel to bedding, along azimuths inclined at various angles to the local and regional structure. The vast majority of the fractures are spaced less than 15 in. (38 cm) apart. The distribution is negatively exponential.

Figure 4b. Compilation of all data in Figure 4a.

Structure Related Fractures — Scalar Data

Corbett et al. (1991a, b) and Wiltschko et al. (1991) measured the spacing of fractures along horizontal scan lines placed on vertical exposures of the Austin Chalk and made detailed 1:12 and 1:48 scaled maps of fractured rock panels in the field (Fig. 3). Frequencies of fracture spacings along both the scan lines and the detailed fracture maps follow a negatively exponential distribution with more than 90% of the fractures spaced less than 15 in. (38 cm) apart (Figs. 4 and 5). Except in the vicinity of graben-in-graben structures, fractures are more closely spaced along scan lines oriented at 60° to 90° to the strike of local structures (Fig. 6). This result substantiates the conventional wisdom of drilling horizontal boreholes perpendicular to the local structures and the Balcones structural trend. Within the graben-in-graben structures, the long axes of intact blocks of rock bounded by frac-

Figure 5. Fracture attributes from maps of fractured rock panel at the Lehigh Quarry, Waco, Texas (Fig. 3 of Wiltschko et al., 1991).

Figure 6. Variation in fracture spacing with the angle between the azimuth of the scan line and the strike of local structure (fault or fold axis) for the fourteen scan lines (Corbett et al., 1991a). Fractures are twice to three times as closely spaced when the scan line is inclined at 60° to 90° to the strike of the local structure.

res are bimodally distributed (Fig. 7) and thereby reflect the orientation of both sets of bounding grabens (Fig. 2d).

Connectivity of Fractures

Recent work on determining the hydraulic properties of networks of finite fractures has shown that fracture connectivity plays a strong role in determining the degree of anisotropy of network permeability (e.g., Long and otherspoon, 1985; Hester and Long, 1990). For simplified model fracture-networks, the degree of connectivity is spatially uniform and may be computed from fracture spacing and the distributions of length and orientation (Hester and Long, 1990). For natural fracture systems, the relationships among spacing, length, orientation and connectivity are unevenly distributed in space and are functions of lithology. Wiltschko et al. (1991) showed that connectivity in the Austin Chalk is a function of clay content and bed thickness. For instance, in the vicinity of San Antonio, Texas, the Atco Member of the Austin Chalk is high in smectite relative to regions to the north and south and more massively bedded. The fractures there are longer and wider spaced. In addition, the number of connections per unit length of fracture are lower than in other regions of study.

Rocks with greater clay content display fewer connections presumably because the compressive strength of

Figure 7. Orientations of the long axes of 357 intact blocks of Austin Chalk as determined from detailed fracture map for Lehigh Quarry, Waco, Texas (Fig. 3). The bimodal distribution agrees with the graben-in-graben structure in the quarry (Fig. 2d).

the Austin Chalk is lower and as a result the fracture density is lower. By contrast, Corbett et al. (1987) found that Austin Chalk (Dessau Member) from Tequesquite Creek (No. 1 on Fig. 1) has the greatest ultimate strength, lowest porosity, and highest smectite content of the areas studied. Also, the fracture intensity and number of intersections per unit fracture length are on average higher there than elsewhere on the trend. Presumably, in this case porosity has a greater influence than clay content on strength. The San Antonio and Tequesquite Creek areas also differ in that there is only one predominant fracture orientation at San Antonio, whereas the distribution of fracture orientation is much more diffuse at Tequesquite Creek.

Although there are not enough data to quantitatively correlate fracture spacing, orientation and length with fracture connectivity, we predict that, all else being equal, the more permeable fracture networks are those where fractures are more closely spaced and more than one fracture orientation is represented. Below, we offer a working hypothesis that correlates fracture abundance (including connectivity) with strength — a hypothesis that is supported by the contrasts described from the San Antonio and Tequesquite Creek outcrops.

THE EXTRAPOLATION PROBLEM

In what respects are fractures in the outcrop similar to those in the subsurface? This question is of critical importance in that while outcrop measurements are essential, they are made in quarries and roadcuts where the rocks are subjected to excavation operations and where fractures might have occurred due to relaxation phenomena at rock/air interfaces. Moreover, the naturally fractured beds now at the outcrop have been uplifted and exhumed and therefore some of the fractures may have formed under conditions of temperature and effective confining pressure significantly different from those at the time of fracturing in the subsurface.

We have attempted to minimize quarrying-induced fractures in our work by including only natural fractures related to local structures. In addition, only fractures with natural filling or parallel to naturally mineralized fractures have been mapped or measured. Fault fabrics and fracture surface morphologies from cores (Corbett et al., 1987) are similar to those we have identified in outcrop, corroborating our approach.

The physical environment under which fractures occurred in the outcrops of the Austin Chalk is one of very low effective confining pressure and temperature. Estimates are that a maximum of 1,000 ft. (328 m) of overburden may have existed during deformation of the chalk along its current outcrop trend. With a normal pore pressure gradient, the effective pressure due to the overburden alone therefore would have been about 500 psi (3,450 kPa) and the temperature only slightly greater

than mean surface temperature. That the effective pressure was low is substantiated by the development of brittle fracture morphologies such as plumose structures, hackle marks, arrest lines, and en passant configurations.

The subsurface environment at the time of fracturing of the Austin Chalk probably also was characterized by low effective pressure. Deformation was brittle as evidenced by calcite and clay vein fillings (Fig. 8) which indicate dilatancy, and the fact that fractures in cores show similar morphologies as observed in outcrop. Moreover, high pore pressures (low effective pressures) are indicated by late dewatering of the underlying Eagleford Shale (Corbett et al., 1991b) and the idea that the Austin Chalk may have served as its own source rock (Hinds and Berg, 1990). Dewatering of the shale late in its compaction history is suggested by clay composition, abundance and trace chemistry of fracture fillings. With regard to the latter, if the chalk served as its own source rock, the chalk and interbedded marls must have self-hydrofractured during the hydrocarbon maturation processes to expel oil and gas to the possibly contemporaneous major fracture systems. This process would have increased the pore pressure and therefore decreased the effective pressure to very low values, thereby enhancing the brittle deformation of the beds and setting the most environmentally sensitive parameter for fracturing — effective pressure — comparable to that for the rocks currently at the outcrop.

We have formulated the working hypothesis that the outcrop data can be used to predict fracture development in the subsurface in the following ways:

- 1.) The orientation of major outcrop fracture sets related to local and/or regional structure may be used reliably to determine the direction of horizontal or inclined boreholes at depth. This is especially true if fractures are partially mineralized because such fractures are unlikely to have formed due to surface processes.

- 2.) Relative fracture abundance/orientation relationships also may be used reliably to: choose the azimuth of proposed boreholes; predict fracture development in hanging wall versus footwall and size of fracture halos; predict fracture orientations in flexures and folds, abundance relative to structural position, and size of fracture halo; recognize the influence of marl breaks on the containment of fractures within beds; and determine the relative importance of grain size, porosity, and clay content on rock strength (Corbett et al., 1987), with the idea that in the brittle regime the stronger rocks will contain the largest fracture surface area and connectivity upon deformation.

- 3.) The fracture spacings and intact block sizes as determined from outcrop studies may be too small (and fracture widths too large) by some as yet unknown factor.

Clearly, point 3 needs to be calibrated in the subsurface. One approach would be to obtain similar fracture data from the subsurface, which is now possible with logging techniques based on acoustic or resistivity imag-

Figure 8. Photomicrograph of intense fracturing and later calcite and clay infilling in a small fault zone in the Austin chalk. Core from 8,974 ft. (2,735 m) in the Petromark Conway No. 1 well, Kurten Field, Brazos County, Texas. Fault zone has overall left-lateral shear sense. Bold arrows indicate an epoxy-filled parting that occurred during handling. Difference in grain sizes of calcite (see open arrow where grain size is coarse) suggests more than one period of mineralization. Note the very closely spaced fractures encased in "pods" or "bar domains" that are bounded by left-lateral shear surfaces. Scale bar equals 0.5 cm (0.2 in.). Sample courtesy of Dr. R.R. Berg, Dept. of Geology, Texas A&M University.

ing from horizontal boreholes. In addition, fractures in cores taken by industry and available in the repositories at the Texas Bureau of Economic Geology and at Texas A&M University, or available through the cooperation of the companies, may be studied. As a case in point, in a vertical core from the Pearsall Field (Exxon/Pinnacle Gise No. 1) obtained through the courtesy of these operators, we observed that fractures within the core tended to terminate near the boundaries of chalk beds where the clay/organic content increases (Fig. 9). This supports the outcrop observation that fractures tend to be contained within the chalk beds where these beds are bounded by shale or marl breaks.

FACTORS CONTROLLING FRACTURE IN ROCK-STRUCTURAL STRATIGRAPHY

It is now reasonably well known from programs of experimental rock deformation that the relative strength and ductility of a rock is dependent upon the interaction of two sets of variables: those inherent in the rock or rock mass and those that define the environment of the defor-

Figure 9. Calcite-filled fracture (arrows) from the Gise No. 1 well, Pearsall Field. Fracture terminates at tip of pointed razor in darker part of the core where there is an increase in shale and organic matter. This vertical core was supplied by the Pinnacle Oil Co. and the Exxon Corp.

mation (Fig. 10). The problem is to define the relative mechanical behavior of strata within a given stratigraphic interval with a view toward identifying those beds that are apt to be most highly fractured at a given depth, hence the term structural stratigraphy.

MECHANICAL BEHAVIOR OF ROCK
DEPENDS UPON
INTERACTION OF

INTRINSIC PROPERTIES AND ENVIRONMENTAL FACTORS

Rock composition including
minor minerals
Grain size
Porosity
Permeability
Size
Bedding thickness
Previously existing discontinuities

Effective pressure ($P_e = P_c - P_p$)
Confining pressure (P_c)
Pore fluid pressure (P_p)
State of Stress
Differential Stress
Temperature
Burial history
Time (strain rate)
Pore fluid chemistry

Figure 10. Factors that interact to affect the mechanical behavior of rock.

It is reasonable to accept the view that the Austin Chalk rocks currently at outcrop and their counterparts in the subsurface both deformed under low effective pressure, i.e., both deformed under reasonably similar (brittle) conditions.

It is known that in the brittle regime fracture abundance increases with increasing percentages of quartz, feldspar and dolomite in the load-bearing framework of the rock, with decreasing clay content, with decreasing porosity, with decreasing grain size, and with decreasing bed thickness. The parameters that enhance strength, alone or in combination, also may enhance fracture abundance upon deformation (Fig. 11a). It follows that one role

Figure 11a. Illustration of a working hypothesis. A. represents brittle failure of a stronger rock with greater Young's modulus (YM) than B. Area under each stress/strain curve is the distortional strain energy, which, upon failure, creates fracture surface in the rock. This area (potential energy) increases as YM and strength increase. After failure, rock with greater strength and higher YM will contain more fracture surface area per unit volume, i.e., greater fracture abundance. This hypothesis holds only when failure occurs in the brittle regime.

of outcrop studies is to identify the relative importance of these parameters in controlling fracture abundance.

For example, earlier work on the mechanical stratigraphy of the Austin Chalk (Corbett et al., 1987) indicates that the upper (Big House Chalk) and lower (Atco Chalk) massive chalk members are the most fractured stratigraphic intervals in outcrop. Moreover, Corbett et al. (1987) found that for Austin Chalk specimens deformed in the brittle regime (i.e., low effective confining pressure) strength is influenced most by porosity and clay (smectite) content. Rock-deformation experiments show that as little as 4 wt% clay decreases the strength 30 to 42% compared to specimens with no clay. We are finding that the fracture susceptibility of the chalk also correlates with strength (Fig. 11b).

Figure 11b. Plot of normalized fracture length and the corresponding distortional strain energy for eight specimens of Austin Chalk experimentally deformed in the brittle regime (Corbett et al., 1987). Fracture length is the total length of fracture traces as observed at the periphery of the deformed cylindrical specimens initially 10 cm (4 in.) long and 5 cm (2 in.) in diameter. Normalization is with respect to the smallest fracture length and the smallest strain energy among the specimens.

It remains to find a way of quickly and economically characterizing the fracture susceptibility of each correlative bed within a given stratigraphic interval. We suggest that logs that measure parameters that correlate with rock strength may be useful. For example, if porosity varied widely and was shown via outcrop studies to be an important fracture-controlling factor in a given set of beds, then porosity logs might be useful. Sonic logs can be used to measure Young's modulus (YM). Therefore, data that relate YM to strength need to be accessed. Pub-

ed data encouragingly indicate that for a number of k types there is strong correlation between YM and compressive strength (Bieniawski, 1984) (Fig. 12). There is similarly strong correlation between YM and tensile strength (Kreck et al., 1974) (Fig. 13). Also, preliminary data for the Austin Chalk from samples obtained from sets of cores from the Pearsall Field show correlation between YM and compressive strength (Fig. 14). It remains to further test the correlations among log data, interval productivity, and the location and abundance of fractures in the subsurface.

12. Relationship between mean uniaxial compressive strength and mean Young's modulus for 10 rock types (after Bieniawski 1984, his Table 5.4). Rock types are as follows: 1-dolerite, 2-gneiss, 3-granite, 4-limestone, 5-norite, 6-sandstone, 7-shale, 8-sandstone, 9-shale, 10-coal.

FRACTURE PERMEABILITY

emphasized by Nelson (1985) and a host of other authors, fracture permeability is essential to the production of naturally fractured reservoirs. That fractures in the Austin Chalk are permeability channels is demonstrated by their productivity, by calcite and clay along fractures, and by chemical alterations both along fractures (liesegang banding) and into the country rock. The maintenance of fracture width and permeability as formation pressure changes is essential not only for initial production but for continued productivity as well. Accordingly, one should evaluate the degree of

Figure 13. Relationships between the tensile strength and the corresponding dynamic Young's modulus for eight rock types (data from Kreck et al., 1974). Rocks are: 1-Berea sandstone, 2-Barre granite, 3-Salem limestone, 4-granodiorite, 5-Westerly granite, 6-Sioux quartzite, 7-Tennessee marble, 8-Dresser basalt.

Figure 14. Relationship between static Young's modulus and compressive strength at 17,000 kPa confining pressure for six specimens of Austin Chalk: three each from the Exxon Hildebrand No. 1 and the Pinnacle/Gise No. 1, Pearsall, Field, south Texas. Data courtesy of Dave Becker, Exxon Corp, Corpus Christi, as obtained by Jack N. Maquoirk, Center for Tectonophysics, Texas A&M University.

fracture closing for changes in effective normal stress across fractures and indeed, predict the likelihood of fracture permeability from a knowledge of the effective pressure and fracture orientation prior to drilling, through use of techniques described by Jones (1975). In addition, the current in situ state of stress may influence fracture permeability as indicated in the models suggested by Nelson (1987, his Fig. 7).

INFERENCES FROM SOURCE-ROCK CONSIDERATIONS

There are special considerations involving the source of hydrocarbons that are useful in working with naturally fractured reservoirs. If the fractured reservoir is its own source, as is believed to be the case for the Bakken Shale and the Austin Chalk, then a high formation pressure (and low effective pressure) probably existed at the time of oil generation. If the oil generation coincided with the development of local structures, the environment of deformation would be favorable for brittle fracturing and relatively low strength. Moreover, fracture closure would be minimal and fracture permeability maximized. Finally, the expanding hydrocarbons would produce hydrofracturing of the formation and thereby create "expulsion fractures" that would serve to transmit the hydrocarbons from the matrix to the larger fracture network. Hinds and Berg (1990) presented a strong argument for self-sourcing of the Austin Chalk.

If the source of the oil is from underlying formations, e.g., the Eagleford Shale beneath the Austin Chalk, then high formation pressures (low effective pressures) also might be inferred that would have the same effect as expressed above. Especially significant in this regard is evidence of late dewatering of the underlying shale (fluid expulsion after significant compaction) from the clay abundance and its chemistry presented by Corbett et al. (1991b). Again, timing of the dewatering relative to the development of the local structures is critical if brittle fracture is to be enhanced by the high formation pressures associated with the dewatering. Moreover, it has been suggested that dewatering of the shale would result in a volume reduction (once the fluids were expelled) that might have triggered the faulting and monoclinical flexuring (K.P. Corbett, pers. comm., 1990). Finally, if the source of the hydrocarbons is from much deeper formations, then the stacking of flexures over normal faults would enhance upward migration into the naturally fractured reservoir target.

AN INTEGRATED APPROACH

We assume that outcrops of the target formation are accessible, logs and perhaps some cores of the typical stratigraphic interval at depth are available, seismic data

exist, and there is some knowledge of production and formation pressures. One starts with studies of outcrops to:

- 1.) determine fracture orientation relative to local and regional structure;
- 2.) determine fracture abundance (spacing, length, connectivity relative to structural position), e.g., inflection regions or hinge lines on folded beds, hanging wall versus footwall adjacent to faults;
- 3.) determine fracture abundance relative to rock type, grain size, porosity, clay content, bedding thickness (determine which factors are most important);
- 4.) determine fracture containment, within or across beds;
- 5.) collect specimens for experimental rock-deformation and compositional analysis;
- 6.) collect data about the physical environment at the time of deformation, primarily the depth of burial.

From subsurface data, one may infer:

- 1.) burial and uplift history;
 - 2.) local/regional structural types, orientations and size;
 - 3.) probable physical conditions at the time of deformation, especially pore pressure and temperature;
 - 4.) structural (mechanical) stratigraphy, i.e., likely relative strength and ductility of stratigraphic interval in question;
 - 5.) source rock maturation and migration timing.
- From experimental rock deformation, one can verify:
- 1.) factors most important to fracture strength;
 - 2.) relation between strength and fracture susceptibility for environmental conditions inferred in subsurface;
 - 3.) fracture closing (permeability reduction) as a function of effective normal stress across fracture surfaces.

Finally, one extrapolates laboratory and outcrop data to the subsurface, calibrating scalar data with appropriate log and core data. It then is possible to build conceptual models of:

- 1.) fracture orientation in structures at depth;
- 2.) fracture abundance relative to structures, hanging walls, inflection zones, hinge lines, etc.;
- 3.) fracture abundance relative to stratigraphy on a given structure;
- 4.) relative fracture permeability vis-a-vis fracture sets and structural configuration.

One then has the background to design efficient drilling plans, based on insight gained about certain key questions. In light of fracture spacing and orientation, is anything other than a vertical borehole required?

If a slanted or horizontal borehole is indicated, in which direction should it be drilled?

What is the optimum borehole trajectory if fractures tend to be confined to brittle layers, i.e., vertical connectivity is poor?

What is the optimum borehole trajectory if there is good vertical connectivity?

Can a given well be located and drilled so as to test more than one conceptual model?

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**EXTRAPOLATION OF FRACTURE ORIENTATION AND
SPACING IN OUTCROPS OF UPPER CRETACEOUS AUSTIN
CHALK, TEXAS, TO CORRESPONDING PETROLEUM
RESERVOIRS**

A Thesis

by

DESIREE ELISABETH MCKIERNAN

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MASTER OF SCIENCE

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Major Subject: Geology

ABSTRACT

Extrapolation of Fracture Orientation and Spacing in
Outcrops of Upper Cretaceous Austin Chalk, Texas, to Corresponding
Petroleum Reservoirs. (December 1993)

Desiree Elisabeth McKiernan, B.A., Northeast Louisiana University

Chair of Advisory Committee: Dr. Melvin Friedman

The success of horizontal drilling in the Austin Chalk naturally fractured reservoir of Texas has focused exploration efforts on other fractured reservoirs around the world. Successfully drilling in these reservoirs requires characterization of the fracture system (i.e. origin, orientation, length and connectivity, and spacing) as well as an understanding of the mechanical behavior of the layered rocks relative to local and regional structure, in order to predict the most highly fractured intervals.

The Austin Chalk fracture system has been extensively studied at the outcrop. The extent to which the outcrop fracture system characterizes corresponding petroleum reservoirs is the focus of this study. Fracture orientation and spacing data from Austin Chalk outcrops were extrapolated to corresponding petroleum reservoirs using Formation MicroScanner Surveys. Over 9,000 fractures in horizontal boreholes, from Pearsall and Giddings fields, were mapped using Schlumberger's Fracview 1.0. software.

On the outcrop at least two sets of cross-trending fractures are identified, however in the eight wells evaluated, only one set of nearly vertical fractures striking NE-SW is identified. This trend is consistent with the regional

stress trajectories, governed by subsidence and extension down-dip into the Gulf of Mexico.

The strike of the NE-SW trending fractures at the outcrop and in the subsurface differ by at most 20°. Spacing distribution data from horizontal scanlines placed along Austin Chalk outcrops indicates that >50% of the fractures are spaced <10 cm apart. The overall shape of the cumulative fracture versus spacing curves in the subsurface is similar to that of the outcrop and indicates >40% of the fractures in the subsurface are spaced <20 cm. The spacing distribution curve of one highly fractured borehole nearly equals that of the outcrop, while the spacing distribution curves for the other wells approaches that of the outcrop such that the outcrop acts as a minimum-spacing-boundary curve. As regional fractures are spaced >45 cm, the spacing distribution data suggest that tectonic fractures relative to NE trending local structures are probably superposed on regional ones in the subsurface just as they are at the outcrop..

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INTRODUCTION

The characterization of naturally fractured reservoirs involves an understanding of the mechanical behavior of the reservoir rock, the origin of the fractures, the orientation (i.e. strike and dip), spacing, and connectivity of the fractures, and the role fractures play in the fluid flow of the reservoir. Naturally fractured reservoirs such as the Austin Chalk (Texas), Bakken Shale (Montana), Purdoo-Bay clastics (Alaska), North Sea Chalks, and the Niobrara Limestone (Colorado) have received a great deal of attention since the advent of horizontal drilling. The great advantage of horizontal drilling over vertical drilling in these naturally fractured reservoirs is the ability to drill perpendicular to the best developed fracture set. In naturally fractured reservoirs, the majority of the fractures lie perpendicular to the sedimentary bedding, hence in flat-lying beds these fractures would be nearly vertical in orientation; the chances of a vertical borehole encountering these fractures are poor unless the fractures are closely spaced relative to the borehole diameter (e.g., Friedman, 1969; Lorenz and Hill, 1991). Productivity of horizontal wells in the Austin Chalk is often five times that of a conventional vertical well (Fritz, 1991). Since 1989, 2,922 horizontal permits have been issued by the Texas Railroad Commission, the majority of these within the Austin Chalk play. Total monthly production from the Austin Chalk in Giddings Field (Figure 1) topped 2.9 million barrels in November of 1992 (Shirley, 1993).

That fractures significantly influence fluid flow in reservoirs is now widely recognized from criteria such as reservoir productivity versus that expected

Style and format to follow that of The Bulletin of the American Association of Petroleum Geologists.

Figure 1--Location of the Austin Chalk productive trend and the approximate location of FMS surveys in database.

from matrix porosity and permeability. Modeling the natural fractured reservoir or predicting its behavior prior to drilling requires an understanding of the origin, morphology, orientation, length and connectivity, and spacing of the fractures as well as an understanding of the mechanical behavior of the reservoir rock (i.e. its propensity to fracture). An in depth study of the factors controlling the fractures of the Austin Chalk (Table 1) has been undertaken by Dr. Mel Friedman (Professor, Texas A&M University), his students, and colleagues. This thesis is a part of this study and is an evaluation of the extent to which outcrop fracture data can be extrapolated to the subsurface. Although studies of reservoir rock at the outcrop can provide details regarding the orientation of fracture set(s), spacing between fractures of a given orientation, length and connectivity of the fractures, and degree of fracture bed containment, the extent to which these data can be extrapolated to equivalent rocks in the subsurface remains uncertain.

Until recently, cores and wireline logs (e.g. the Fracture Identification Log) were the only means available to make correlations between the subsurface and the outcrop (e.g. Corbett, 1987). Within the last five years, however, Schlumberger Well Services has developed the Formation MicroScanner (FMS), a microresistivity wireline log, which provides a high resolution image of the borehole that resembles core photographs. FMS surveys used in conjunction with software developed by Schlumberger (Fracview 1.2) allow structural features such as fractures to be mapped in detail. The FMS tool, therefore, provides exactly the type of data needed to evaluate the extrapolation question.

Table 1. Factors Controlling Fractures in the Austin Chalk.

COMPONENT	PURPOSE	PUBLICATIONS
Develop Mechanical Stratigraphy	To determine factors which control fracturing of the Austin Chalk. The primary factors controlling fracturing are porosity, clay content, and differential stress. The Big House and The Atco members of the Austin Chalk are the most highly fractured.	Corbett and others, 1987
Characterize Outcrop Structural Types	To identify the orientation of tectonic fractures associated with specific structures such as folds and faults also identified in the subsurface.	Corbett and others, 1991a and 1991b
Characterize Fracture Development	To predict the origin of the fracturing as well as to characterize the subsurface reservoir the orientation, spacing, length and connectivity, morphology, and mineralization are characterized at the outcrop.	Corbett and others, 1991b Willschko and others, 1991
Extrapolate Outcrop Fracture Data to Subsurface	To determine the usefulness of outcrop fracture data for subsurface fracture characterization.	This thesis
Experimental Deformation of the Austin Chalk	To determine the relationship between Young's Modulus, resistivity, fracture abundance, and fracture strength with the view that a strong correlation provides a sound basis on which to use logs to identify potentially highly fractured units.	Friedman and Kwon, 1992
Correlate the above to Chalk Productivity	To assess the importance of the above components in predicting not only where to drill but the potential productivity of the well.	
Extrapolate to other fractured reservoirs	To establish the Austin Chalk as a generic naturally fractured reservoir with the view that the same components studied here are of equal importance to the understanding of other naturally fractured reservoirs.	Friedman and Willschko, 1992

Objectives

The objectives of this study are to (1) ascertain fracture orientation and spacing in the subsurface, through the use of the FMS, (2) compare these data with the outcrop data previously gathered, (3) establish the limitations (if any) of the FMS tool for this type of study, and (4) take initial steps in the development of a detailed fracture stratigraphy for the Austin Chalk.

The primary goal of this thesis is to establish the extent to which fracture orientation and spacing data gathered at the outcrop can be used to characterize the equivalent fractured reservoir rock in the subsurface. FMS surveys were evaluated to determine fracture orientation and spacing in the subsurface (see Appendix A and Results). The data gathered from the FMS surveys are then compared to previously gathered fracture outcrop data (see Table 1). A secondary goal is to establish a detailed mechanical (fracture) stratigraphy for the subsurface. To this end, an attempt is made to determine the stratigraphic position of the horizontal boreholes relative to electric logs from nearby vertical wells. Limitations in available data significantly curtailed this effort as explained in Appendix C. Fracture density (i.e. fractures per linear foot) along the horizontal borehole was compared to gamma ray response to contribute to the recognition of a fracture stratigraphy.

Data Base

Outcrop fracture data available for this study include (1) spacing of fractures along 14 detailed scanlines placed on subvertical quarry walls, simulating possible orientations of horizontal boreholes relative to local and regional structure (Corbett et al., 1991a) and (2) fracture orientation spacing and connectivity data relative to local structure (folds, normal faults, flexed

zones above faults) as mapped on scales of 1:12 and 1:48 and characterized on block diagrams (Corbett et al., 1991a, 1991b). These outcrop fracture data represent measurements taken along the outcrop trend from selected exposures and quarries in Dallas, Waco, Georgetown, Austin, San Antonio, Uvalde, Del Rio, and Langtry (Figure 2).

Subsurface data included a total of sixteen FMS surveys. Of the sixteen, seven were chosen for evaluation on the basis of quality of the FMS data, location, and availability of electric logs from nearby vertical boreholes. Included in the subsurface database is a detailed study of fractures in core from the horizontal well Kinlaw Oil B-1 Newson (Frio County, Pearsall Field) (Grier and Malek, 1991).

Figure 2--Map showing the location of the outcrop sampling, the outcrop trend and regional structural features influencing the fractures of the Austin Chalk.

BACKGROUND

Depositional Environment

The Austin Chalk, like the North Sea Chalk, was deposited during a late Cretaceous worldwide marine transgression. The Austin Chalk is primarily a coccolith-rich limestone. Although chalks in general are considered to have widespread uniformity of facies (Stapp, 1977), the San Marcos Arch (Figure 2) created paleobathymetric variations which greatly affected the primary composition and mineralogy of the Austin Chalk along its productive trend (south and central Texas) (Corbett, 1982; Dravis, 1991).

A relatively shallow marine carbonate ramp was created by the San Marcos Arch with water depths gradually increasing to the south, southeast, and the southwest of the ramp (Dravis, 1991). The Austin Chalk between Austin and San Antonio is light in color and contains abundant shallow marine benthonic skeletal material as well as lime mud. Diagenesis and porosity of the Austin Chalk were greatly affected by these up-dip shallow marine deposits which were high in original aragonite and high-magnesian calcite grains and micrite (Durham and Hall, 1991; Dravis, 1991). The chalk thins across the Arch and thickens to the northeast and southwest in the deeper basinal settings created by the Rio Grande and East Texas Embayment. The basinal chalks deposited off the San Marcos Arch generally are darker in color and are composed of calcareous microfossils and nannofossils (Dravis, 1991). In the San Antonio area (Pearsall Field), the basal chalk unit (Atco Chalk) is massive with intervening marl layers of < 1.0 cm (Corbett, 1991b). As the depositional environment becomes more basinal to the north (from Waco to Dallas), the intervening marl layers of the Atco become thicker and more numerous.

The Austin Chalk to the north and north-east of the Angelina-Caldwell flexure (Figure 2) was deposited in a relatively shallow epicontinental sea (Dutton et al., 1993) and is characterized by chalk/marl cycles (Stelhi et al., 1972). The Atco Member, near Waco, is characterized by chalk beds ranging in thickness between 25 cm and 3 m (9.8 in and 9.8 ft) and intervening marl beds ranging between 4 cm and 0.5 m (1.6 in and 1.6 ft) (Corbett, 1991b).

Volcanic activity concurrent with the deposition of the Austin Chalk further contributed to the mineralogical variations seen in the chalk. Discrete bentonite beds as well as feldspar, kaolinite, and chlorite found in both surface and subsurface samples, documents contemporaneous volcanism (Corbett, 1982).

In summary, the Austin Chalk is not a uniform lithology. The primary mineralogy and composition of the chalk are influenced by variations in paleobathymetry as well as contemporaneous volcanism.

Diagenesis

In general, chalk has a very stable composition (low-magnesium calcite) and therefore chalk diagenesis is primarily restricted to porosity loss due to burial. Diagenesis of the Austin Chalk, however, is more complex than that of "classic" chalks due to its mixed primary mineralogy. Diagenetic processes operative within the Austin Chalk includes (1) dewatering of coccolith ooze, (2) volcanic ash devitrification, (3) stabilization of aragonite to calcium carbonate cements, and (4) pressure solution (Dutton et al., 1993; Dravis, 1991). Figure 3 shows porosity loss in chalk as a function of depth. The "normal curve" represents the simplest case of porosity loss with compaction (Dravis, 1991; Fritz, 1991). The "maximum curve" and the "minimum curve" show anomalous

Figure 3--Porosity loss with depth. The "maximum curve" represents porosity loss for the Austin Chalk, the "normal curve" represents the porosity loss for a "classic" chalk such as the North Sea Chalks, and the "minimum curve" exemplifies porosity loss for the Ekofisk Chalk. (After Fritz, 1991).

porosity loss with depth when factors beyond physical compaction (e.g. fluid chemistry, pore-fluid pressure, tectonic stresses, and chemical compaction) influence the diagenesis (Dravis, 1991).

Compared to the porosity of the more typical North Sea Chalk, the Austin Chalk has unusually low porosity at the surface and in the subsurface. Porosity from outcrop plug samples range from < 10 to 28 %. Porosity values for the deeper hydrocarbon bearing chawks at 304 to 2438 m (1000 to 8000 ft) (Figure 4) are reported by Dravis (1991) to range between 3 and 16 percent. The difference in porosity between the outcrop and the subsurface is due, in part, to differences in the maximum depth of burial. The maximum burial of the Austin Chalk along the outcrop trend is approximated to be < 915 m (3000 ft) (Gabrowski, 1985, cited in Corbett, 1982) while that along the Texas producing trend is ~3 km (8,000 to 12,000 ft).

The loss of porosity in the shallow marine deposits of the Austin Chalk is attributed to early physical compaction. Calcite cementation due to the freshwater diagenesis of the unstable high-magnesium components of the Austin Chalk further contributes to the porosity loss of the shallow-marine deposits (Dravis, 1991). For the deeper basinal chawks, porosity loss is attributed not only to compaction but also to pervasive pressure solution and associated calcite cementation (Dravis, 1991). Unusually high porosity values observed at depth are due to diagenetic variations between the positionally deeper chawks and those shallow-marine chawks brought into deeper water environments by debris-flow. These shallow-marine chawks, higher in aragonite, become unstable with burial and temperature increase and alter to more stable low-magnesium-calcite cements. This stabilization

Figure 4--Schematic of the Austin Chalk outcrop downdip into the productive trend. Porosity values average 20% at the outcrop but drop to between 3% and 16% in the subsurface. (Modified from Fritz, 1991).

process is accompanied by a volume increase, due to larger unit cell dimensions of calcite, as well as calcite cement, the end result being a lithified framework strong enough to withstand the effects of pressure solution (Dravis, 1991). Another important diagenetic component of the Austin Chalk is devitrification of volcanic ash; attributed to the authigenic precipitation of clay (Dutton et al., 1993).

In summary, porosity loss in the Austin Chalk is due to physical compaction, pressure solution, calcite cementation, and authigenic precipitation of clay. Further, differences in the primary mineralogy and composition influences porosity loss.

Stratigraphy

The Austin Chalk is Late Cretaceous in age; specifically it ranges in time from the base of the Cenozoic stage (88.5 ma: Harland et al.) to the top of the Santonian stage (83 ma: Harland et al.). The Austin Chalk is bounded by the Eagleford and the Taylor Marl. The base of the Austin Chalk contact with the Eagleford Shale is conformable south of Del Rio, grades into a disconformity northeast of Del Rio towards Uvalde, and is unconformable from San Antonio north to Red River County. The Taylor Marl lies unconformably on the Austin Chalk from Langtry to north of Waco where it grades to a disconformity; north of the Dallas County line the contact becomes conformable (Corbett, 1982).

The Austin Chalk outcrops sporadically from Red River County in northeast Texas to Val Verde County in southwest Texas following the general trend of the Gulf Coast Geosyncline and Balcones Fault Zone (Figure 2). The subsurface chalk parallels the outcrop to the east and southeast dipping toward the Gulf. The Austin Chalk is characterized by

streaks of marl or shaly marl which range in thickness from as little as 2.54 cm to as much as 7.6 m (1 in to 25 ft). In the subsurface, the chalk varies in color and composition; gradually changing from a white chalk, near the outcrop, to a black shale with no chalk or limestone component below 3962 m (13,000 ft) in Bee and Karnes Counties (Stapp, 1977).

The stratigraphy of the Austin Chalk along the outcrop trend was established by Pessagno (1969, cited in Corbett et al., 1987) and Durham (1957, cited in Corbett et al., 1987) (Figure 5). The outcrop stratigraphy of the Austin Chalk in the Rio Grande Embayment is very similar to that of Central Texas. Specifically the Dessau-Burditt-Big House sequence corresponds in thickness, lithology, and fossil content despite the 384 km (240 mi) separation across the intervening San Marcos Arch. Since the Austin Chalk thins and changes facies over the arch, the striking similarity in facies between the stratigraphic sections of the Rio Grande Embayment and of Central Texas indicates that the depositional environment of these units extended downdip and around the southern portion of the San Marcos Arch, in what is now the deep subsurface (Durham and Hall, 1991).

The Austin Chalk varies in thickness along the outcrop trend due to erosion and faulting. As much as 183 m (600 ft) of Austin Chalk outcrop is recorded in Kinney County while an average of 71 m (233 ft) is found in the Waco area (Corbett, 1982).

The stratigraphic units of Central Texas, as described by Durham and carried into the subsurface by Koger (1957; 1981; cited in Thornhill, 1982), are correlated to the Giddings Field area by Thornhill (1982) (Figure 6). The subsurface stratigraphic section for Giddings field resembles that of the Dallas outcrop sequence, specifically a lower Atco member, Bruceville middle

Figure 5--Lithostratigraphic correlation of the Austin Chalk along the outcrop trend. (After Corbett, 1982.)

DURHAM (1957)	KOGER (1981)	THORNHILL (1982)
CENTRAL TEXAS OUTCROP	CENTRAL TEXAS SUBSURFACE	GIDDINGS FIELD AREA
Lower Taylor Marl	Lower Taylor Marl	Lower Taylor Marl
Big House Chalk	Pflugerville Chalk	
Burditt Chalk Marl	Burditt Chalk Marl	Hutchins Chalk
Dessau Chalk	Dessau Chalk	
Jonah Chalk	Jonah Chalk	
Vinson Chalk	Vinson Chalk	Bruceville Chalk Marl
Atco Chalk	Atco Chalk	Upper Atco Chalk
		Lower Atco Chalk
Eagleford	Eagleford	Eagleford

Figure 6--Stratigraphic divisions of the Austin Chalk correlated from the outcrop to the subsurface of Giddings Field. (Modified from Thornhill, 1982.)

marl member, and Hutchins upper chalk member (Durham, 1991). A maximum thickness of 244 m (800 ft) of Austin Chalk is found in the subsurface of Lee County. Moving northeast into Burleson County a maximum of 68.5 m (225 ft) of erosion is found in the Waco channel (Durham and Hall, 1991). The Waco channel has been documented as an erosional channel over 80 km (50 mi) wide (striking NE from Bell to Dallas counties), 160 km (100 mi) long (trending northwest to southeast from McLennan to Brazos counties), and over 213 m (700 ft) deep in Burleson County (Figure 2) (Durham and Hall, 1991). Within the Waco Channel, the entire upper Austin Chalk sequence is missing and the Taylor Marl lies disconformably on the middle Austin Bruceville Member (Durham and Hall, 1991). Podell et al. (1993) argue that the "Waco channel" is not an erosional feature but is actually the result of "changes in chalk sequence geometry in close proximity to the San Marcos Arch" (p. 95).

Operators in Pearsall Field informally divide the Austin Chalk into a lower chalk, a middle chalk marl, and an upper chalk (Fritz, 1991). Corbett et al. (1987) suggests that the lower chalk corresponds to the Atco Chalk member, the middle chalk marl is equivalent to the Burditt Marl and Dessau Chalk members, and the upper chalk is equivalent to the Big House Chalk member. A correlation between outcrop units in Central Texas and the subsurface of Pearsall Field is suggested by Durham and Hall (1991) (Figure 7). The Atco and Bruceville Members are equivalent to the E and D units of Pearsall Field, respectively. The middle chalk, unit "C", is bounded by two pyroclastic clay beds, while the "B" and "A" units are separated by a persistent bentonite bed. The "C", "B", and "A" units are equivalent to the Jonah and Dessau chalk members. The upper chalk marl, Burditt member, is

Figure 7--Suggested correlation between the subsurface Austin Chalk units of Pearsall Field and surface units of Austin Chalk in Central Texas. (Modified from Durham and Hall, 1991).

only present in the northwestern portion of the field. The Taylor marl lies unconformably on the Austin Chalk sequence throughout the field area (Durham and Hall, 1991). Within the field, the Austin Chalk thickens to the southwest from 91 m to 152 m (300 to 500 ft).

Fracture Mechanics

The mechanical behavior of rocks is influenced by the relationship between intrinsic properties of the rock (e.g. porosity, composition, grain size) and environmental factors (e.g. confining pressure, pore fluid pressure, temperature, strain rate) at the time of deformation. Experimental deformation of rocks in the brittle regime (i.e. low effective confining pressure and temperature) shows that strength increases with decreasing grain size, decreasing porosity, decreasing clay content, and increasing quartz and feldspars in siliciclastics and dolomite in carbonates (e.g. Nelson, 1985, p. 151-166).

In experimental studies of the Austin Chalk, Corbett (1982; Corbett et al., 1987) linked strength variations in the chalk to specific intrinsic properties of the chalk. The effects of porosity, mineralogical composition, and differential stress on the strength of the chalk were evaluated. The experiments were conducted within the brittle regime. The stress-strain curves, from the experiments, show that the upper chalk members are brittle while the middle chalk is ductile under conditions of relatively low confining pressure. Porosity and smectite content were found to have the strongest influence on the strength of the Austin Chalk. Increased porosity and smectite content corresponded to a decrease in rock strength. Corbett (1987) reports that as little as 4 % smectite content is sufficient to reduce the

strength of the rock by as much as 30 % (at 10 MPa; 42% at 70 MPa). In SEM photomicrographs the clay appears as discrete particles. Corbett (1987) suggests that the clay weakens the chalk by acting as a soft inclusion. (A soft inclusion acts as a stress riser such that local failures occur, propagate, and coalesce to macroscopic failure at relatively small external loads.) Dutton et al. (1993) report that SEM photomicrographs of the middle chalk, in shallow cores from Ellis County, show authigenic clay coating the matrix grains of the chalk. They hypothesize that the weakness of the middle chalk is due to this clay coating causing slip on the microscale.

Relative to porosity alone, the results of Corbett et al. (1987) were recently confirmed for porous chalks (10-30%), containing no clay, in experiments run by O. Kwon as part of the TAMU study. The triaxial strength of the chalk (at 10 MPa confining pressure) increases with decreasing porosity (correlation coefficient of 0.95) (Figure 8).

Fracture abundance can be correlated to the ultimate strength of the rock (i.e. the stronger the rock the more fractures) (e.g. Friedman and Wiltschko, 1992). A possible explanation for this correlation is that in brittle rocks the amount of distortional strain energy increases with rock strength. Figure 9 shows schematic stress-strain curves for two brittle rocks. The stronger rock has a larger area (distortional strain energy) under its stress-strain curve than does the weaker rock (although both fracture brittely). When the differential stress equals the fracture strength, much of the released distortional strain energy goes into making new fracture surface area; therefore, other factors being equal, the stronger rock should, upon brittle failure, show the greater fracture abundance. Friedman and Kwon (1992, unpublished data) plot fracture length and ultimate strength against

(A)

(B)

Figure 8--Data (A) show a strong correlation between ultimate strength and porosity, for outcrop samples of the Austin Chalk. K&A Laboratory, Tulsa, OK determined the porosities for the seven Austin Chalk samples using a helium saturation technique. The above samples have very low clay content (T_r to 1%). The stress/strain curves (B) show that the strongest rock (Dallas Lafarge) (which is also the lowest porosity rock) has the greater amount of distortional strain energy (see Text and Figures 9 and 10). (Graphs from M. Friedman, 1993, personal communications.)

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distortional strain energy and found that there is an excellent positive relationship between these parameters (Figure 10). If, however, under favorable loading conditions the differential stress necessary to break the stronger rock is not met it will be the "weaker" rock which is actually the more highly fractured.

Ultimate strength also has been plotted against various electric log values with a view toward identifying potential fracture zones. Operators in the trend have empirically correlated higher resistivity with greater fracture intensity. A plot of resistivity versus ultimate strength shows a positive linear relationship (Figure 11A) (M. Friedman, 1993, personal communications). It has been noted that increased oil saturation is associated with increased fracturing (D. Jenkins, 1993, personal communications). Percent oil saturation for each sample was superimposed on the resistivity versus strength plot (Figure 11B); within the range of 0 to 14 percent oil saturation a reasonably good positive linear relationship exists. It is suggested by Berg (1993, personal communication) that the two samples which show the "anomalously" high oil saturation values (Gise well; 67% and 78%) are from the Eagleford Shale and not from the chalk. Gamma ray values were then superimposed on the resistivity versus strength plot (Figure 11C) (R. Berg, 1992, personal communications). Assuming that the gamma ray value accurately reflects the clay content, lower ultimate strength values should correspond to higher gamma ray values (i.e. the greater the clay content the weaker the rock); and this is seen within the narrow range of 19 and 33 API units. The weakest sample is perhaps influenced by the relatively high clay content (gamma ray value of 52). It should be noted that since gamma ray

Ultimate strength vs. Strain energy

(A)

Fracture length vs. Strain energy

(B)

Figure 10--A positive linear relationship exists between ultimate strength and distortional strain energy (A) and between fracture length and distortional strain energy (B). (From O. Kwon and M. Friedman, 1992, personal communications.)

Figure 11--A relatively good positive linear relationship exists between deep induction resistivity and ultimate strength (A). This relationship has a correlation coefficient of 0.8 for samples with low (0-22%) oil saturation (B) and within a narrow range of gamma ray values (19-33, C).
(From R. Berg, 1992, personal communications.)

measures radioactive elements it is not necessarily a good assumption that gamma ray values correspond directly to clay content.

Behseresht (1992) attempted to establish a relationship between resistivity, production (initial and long term), and fracture abundance. Although no obvious relationship could be established between the three parameters, his study highlighted the points that more than one log must be used to predict potential zones of high fracture abundance and furthermore, that correlation of log response to fracture abundance will be site specific (i.e. the petrophysical characteristics of the section must be taken into account).

Mechanical Stratigraphy

A gross mechanical (i.e. fracture) stratigraphy for the Austin Chalk was established by Corbett (1982; Corbett et al., 1987) for the outcrop and extrapolated into the subsurface along the Austin Chalk trend. Collins et al. (1992) and Dutton et al. (1993) have established a slightly more detailed fracture stratigraphy for the Austin Chalk in Ellis County.

Corbett et al. (1987) used fracture intensity in outcrops to define the mechanical behavior of the Austin Chalk. The larger the average number of fractures per linear meter the more brittle the rock. At the outcrop, mean fracture intensities of 5.80, 2.60, and 6.33 fractures per meter were recorded for the Atco Chalk Member, Dessau Chalk and Burditt Marl Members, and the Big House Chalk Member, respectively. The relative fracture intensity of experimentally deformed samples agrees with those of the outcrop (Corbett, 1982; Corbett et al., 1987). The mechanical stratigraphic divisions of the chalk are as follows (Figure 12A): the Atco Chalk Member corresponds to a lower massive brittle chalk; the Dessau Chalk and Burditt Marl Members

(A) Corbett et al. (1987)

(B) Collins et al. (1992)

Figure 12--(A) Average fracture intensity in outcrop and corresponding mechanical stratigraphic units. (From Corbett et al., 1987.) (B) Austin Chalk in Ellis County divided into thirteen units on the basis of fracture intensity. (Modified from Collins et al., 1992.)

correspond to a middle, ductile chalk-marl; and the Big House Chalk corresponds to an upper, massive, brittle chalk. Corbett et al. (1987) use the term massive to indicate that the stratigraphic unit acts as a single, homogeneous mechanical unit (i.e. individual beds do not behave independently). When intervening marl layers exceed a value of one-tenth the thickness of the surrounding chalk beds, fractures will terminate at the marl boundaries and each chalk bed is considered a single mechanical unit (Corbett et al., 1987). The intervening marl layers of the Atco, as mentioned earlier, become thicker from Waco to Dallas. Notwithstanding the influence of the marl beds the overall fracture stratigraphy prevails (Corbett, 1987).

Corbett (1982; Corbett et al., 1987) analyzed five cores and 22 FILs (Fracture Identification Logs) and determined that the mechanical stratigraphy established for the outcrop trend can be extrapolated to the subsurface (i.e. fracture intensity is highest in the upper and lower third of the chalk). Shallow cores (near surface to 130 m:425 ft) from the Superconductor Super Collider site were used to establish the fracture stratigraphy of the shallow subsurface Austin Chalk in Ellis County. Collins et al. (1992; Dutton et al., 1993) divided the chalk into 13 stratigraphic units based on gamma ray response and fracture spacing (Figure 12B). Overall, their observations support Corbett's mechanical divisions although they note "important variations" in brittleness within the three major Austin Chalk intervals.

Fracture Studies

Fractures of the Austin Chalk are of two types, regional and tectonic (Snyder and Craft, 1977; Thornhill, 1982). Regional fractures are (1) developed over large areas; 2) extension fractures perpendicular to bedding

surfaces; (3) strongly oriented with variations within ± 20 degrees; (4) typically spaced > 25 cm (10 in) apart, depending upon bedding thickness; and (5) commonly developed into orthogonal sets with one set (the "systematic" one) composed of longer, older, and more consistently oriented fractures than those of the "non-systematic" set (Nelson, 1985; Lorenz et al., 1991). Tectonic fractures are those associated with localized folding and faulting. Since local structure tracks the regional Balcones Fault trend at least one set of tectonic fractures is apt to parallel one set of regional fracture sets.

Studies of the Austin Chalk at the outcrop show fracture intensity increases when influenced by some local tectonic event (e.g. Strapp, 1977; Corbett et al., 1987; Collins et al., 1992). Structural settings identified at the outcrop to be associated with increased fracturing include plunging anticlines, listric normal faults, grabens-in-grabens, and monoclinial flexures (Corbett, 1982; Corbett et al., 1991a, b; Collins et al., 1992). Seismic sections, though Austin Chalk prospects, detect structures similar in size and complexity as those mapped at the outcrop. Fracture size, width, aperture, attitude, orientation, spacing, and connectivity vary in relation to structural position (Collins et al., 1992). Fracture swarms (isolated groups of closely spaced fractures) are a persistent, albeit sparse, component of the fracture pattern in Ellis County (Collins et al., 1992). In some cases these swarms have been correlated with minute changes in dip ($< 0.5^\circ$).

Normal faults in the Austin Chalk, at the outcrop, are associated with a "halo" of closely spaced fractures. Fracture intensity is greatest (29 frs./m) in the San Antonio area; which coincides with the most abundant faulting in the Balcones System (Corbett et al., 1987). Although intensity of fracturing does

not seem related to the amount of throw, fracture intensity and connectivity dramatically increase with proximity to the master fault. The effects of tectonic fracturing die out within 60 m (200 ft) of the master fault; furthermore, with distance from the master fault, fractures tend to die out within individual chalk beds (Collins et al., 1992; Corbett et al., 1991a). Faults are commonly associated with veins, although which occurs first is not known (Corbett et al., 1991a, b; Collins et al., 1992).

In the absence of tectonic influences, an excellent correlation between bed thickness and fracture spacing in the Austin Chalk outcrop at the Waco quarry has been documented (V. French, 1992, unpublished data). In this section of the Atco, characterized by conspicuous shale/marl breaks and corresponding containment of fractures within chalk beds, fracture spacing is about equal to bed-thickness of the chalk.

Fracture spacing along the outcrop shows a negative exponential distribution, skewed to the more closely spaced fractures (within 6 cm) (Figure 13) (Corbett et al., 1991a; Wiltschko et al., 1991). The fracture spacing data comes from maps of quarry floors and from scanlines placed on nearly vertical outcrops in areas away from local tectonic events with no distinction made between "regional" and "tectonic" fractures (Corbett et al., 1991; Wiltschko et al., 1991).

Between 60 and 80 percent of the fractures measured along the outcrop strike NE-SW, parallel to the Balcones Fault System (Corbett, 1982). A cross-trending NW-SE fracture set is noted in both core (Corbett, 1982; Collins et al., 1992) and the outcrop (Corbett, 1982; Corbett et al., 1991a; Collins et al., 1992; Wiltschko et al., 1991). Contoured initial potential maps

Figure 13--Along the outcrop trend fracture spacing is such that the largest number of fractures are spaced ≤ 6 cm apart. This data set includes 1011 fracture spacings collected from scanline data from nearly vertical outcrops of the Austin Chalk. (From M. Friedman, 1992, personal communications.)

of Giddings Field indicate the presence of both a NE-SW and a NW-SE fracture trend (Thornhill, 1982). The orientation of both fracture sets changes systematically from Dallas to Langtry (Figure 14). Between Langtry and Uvalde, the NW-SE trend dominates whereas between Uvalde and Dallas the NE-SW trend dominates (Corbett, 1982). The fractures within these two sets are found to have an essentially vertical dip in both core and outcrop (Corbett, 1982; Collins et al., 1992; Snyder and Craft, 1977). From Fracture Identification Logs, Corbett (1982) determined that the NW-SE set was most commonly developed fracture set in the subsurface. A number of structural studies of the Austin Chalk outcrop in the Austin Area (Hays, Travis, and Williamson Counties) show that an orthogonal set of fractures exist with the preferred orientations being between N40°-60°E and N40°-70°W (Table 2).

The longest fractures are those that run parallel to the Balcones Fault System (Wiltschko et al., 1991). In Del Rio and Dallas, fracture connectivity is greatly enhanced by the presence of curved, "chicken wire" fracturing. These fractures are randomly oriented and are possibly due to uniform stretching of the chalk beds within the bedding plane. These "chicken wire" fractures are best developed in areas where the chalk has a high percent of intercalated marl beds; in San Antonio, where the chalk is massively bedded, few curved fractures exist (Wiltschko et al., 1991).

The origin of the fractures which trend parallel to the Balcones Fault System may be related to extension caused by subsidence of and movement into the Gulf of Mexico. The secondary set trending NW-SE is possibly a result of "periodic sagging or warping between structural highs (e.g. Belton High, Llano Uplift, San Marcos Arch)" (Thornhill, 1982, p. 74). Movement along the Balcones Fault System may have begun as early as the Late

Figure 14--Stereograms illustrate the changes in orientation of fracture sets along the Texas outcrop trend. (From Corbett, 1982.)

Table 2. Orientation of Fracture Sets from Previous Structural Studies of Cretaceous Rock Outcrops from Hays, Williamson, and Travis Counties.

STUDY	NUMBER OF FRACTURES (FORMATION)	LOCATION	COMMENTS
Kurie (1956)	802 (Austin)	Austin	39 % of Faults Dip West Fractures Vertical to Subvertical N40°E Preferred Orientation
White (1960)	? (Austin)	Pilot Knob	Faults Dip West Fractures Vertical to Subvertical N40°E Preferred Orientation Radial Fracture Pattern Associated with Plug
Balke (1958)	417 (Glenrose and Edwards)	Mount Bonnell Fault	Faults Dip West Fractures Vertical to Subvertical N40°E Preferred Orientation
Davis (1962)	162 (Edwards)	Hays County	Dominant Orientations include: East-West, North-South, N40° - 45°E, N40° - 45°W
Dunaway (1962)	3233 (Cretaceous Limestone)	Travis County (Along Balcones Fault System)	Dominant Orientations include: N45°E and N45°W
Rogers (1963)	979 (Walnut Creek, Conanche Peak, Edwards, Georgetown)	Williamson County	Dominant Orientations include: N20° - 30°E and N60° - 70°W
Evans (1965)	1052 (Austin) 4083 (?)	Williamson County	Dominant Orientations include: N50° - 70°W and N60° - 70°E
Leonard (1977)	389 (Cretaceous rocks)	Val Verde County	Dominant Orientations include: N40° - 50°W and N40° - 50°E

Cretaceous. In the Giddings Field faulting occurred as recently as the Eocene (Wiltschko et al., 1991).

Environment of Deformation

Extrapolation of outcrop fracture orientation and spacing to the subsurface implies that similar conditions existed between the outcrop and the subsurface at the time of deformation (i.e., to produce similar brittle fractures).

Natural fractures in outcrop were deformed under very brittle conditions as is evidenced by plumose structures, hackle marks, arrest lines, and en passant configurations (Corbett et al., 1987). This implies conditions of very low effective confining pressure and low temperature. If maximum burial for the outcrop is assumed to be approximately 1,000 m (3280 ft) then the effective confining pressure due to overburden alone, assuming a normal hydrostatic gradient, would be a maximum of ~11 MPa (1640 psi) with temperatures at most only twice the mean surface temperature (assuming 8°C per 300 m).

Brittle deformation in the subsurface is suggested by indications of dilatancy and similar fracture morphologies as that seen at the outcrop (Corbett et al., 1987; Collins et al., 1992). To have comparable brittleness between the outcrop and the subsurface requires an increased pore pressure at the time of fracturing to decrease the effective pressure to that estimated for the outcrop. Late dewatering of the Eagleford Shale is a possible source of increased pore pressures. Evidence includes a large volume (18% to 25%) of smectite clay in the veins, depletion of trace elements within the chalk, and high fluid inclusion homogenization temperatures for calcite of the

mineralized zones in the chalk (Corbett et al., 1991b). Excess pore pressures might also be generated by the maturation of hydrocarbons. If the Austin Chalk is self-sourcing (e.g. Snyder and Craft, 1977; Hinds and Berg, 1991), expulsion fractures may have been caused by the generation of gas and oil during hydrocarbon maturation (e.g., Chanchani, 1993, unpublished data; Duppenbecker et. al., 1991). In either case, pore pressures were likely increased over normal values thereby decreasing the effective pressure such that both the subsurface and the outcrop were under similarly low effective stresses at the time of deformation (Corbett et al., 1991b).

The Austin Chalk Play

Over the past 58 years the Austin Chalk has seen a number of drilling booms, the latest initiated by the ability to drill horizontally at reasonable cost. The success of horizontal drilling is credited to the ability to drill perpendicular to the vertical fractures in the Austin Chalk.

Since 1989, 2922 horizontal drilling permits have been issued by the Texas Railroad Commission; most of those in the Austin Chalk play (Shirley, 1993). The two major Austin Chalk fields of south and central Texas are Pearsall and Giddings fields. Pearsall Field, one of the earliest and most prolific fields, hit a high of 2.1 million barrels for its total monthly production in January 1991 (Shirley, 1993). The monthly production from Giddings Field hit 2.9 million barrels in November 1992 (Shirley, 1993).

The source of Austin Chalk hydrocarbons is a matter of debate although strong cases have been made for the Austin Chalk being, at least in part, self-sourcing (e.g. Hind, 1990; Hinds and Berg, 1991). Hinds and Berg (1990) recognize three zones of organic maturity identified from log well response: (1)

an immature zone from 0 to 1828.8 m (0 to 6000 ft) with resistivities below 9 ohm-m; (2) a peak generation zone from 1828.8 to 2133.6 m (6000 to 7000 ft) with resistivities above 40 ohm-m; and (3) a migration and potential reservoir zone between 2133.6 and 2895.6 m (7000 and 9500 ft) with resistivities between 9 and 40 ohm-m.

Giddings Field

Giddings Field covers 1000 square miles and is the largest oil or gas field in the Texas Gulf Coast (Figure 1). The Giddings discovery well was the Union Producing Co. Pruess No. 1 well completed in October 1960 (Horstman, 1987). The thickness of the chalk changes radically throughout the field; being 37 m (130') thick over the San Marcos Arch, thickening to 183 to 244 m (600 to 800 ft) in central Giddings, and thinning again in northeast Burleson County to approximately 30 m (100 ft). A middle marl separates the upper and lower chalk at Giddings field (Durham and Bobigian, 1990). Consistently the best production in the field is found in the lower 61 m (200 ft). (e.g. Drake, 1991; Horstman, 1987). An example log for Giddings Field is presented by Corbett et al. (1991b). The top of the Austin Chalk ranges in depth from 1859 to 3658 m (6,100 ft to 12,000 ft). Regional structural dip is 200 ft per mile (Horstman, 1987). Porosity is between 1.6 and 8 percent and the reservoir is normally pressured. Fracturing is due to small scale faulting and drape over a deeper buried shelf margin (e.g. Durham and Bobigian, 1990; Drake, 1991). Faulting is more prevalent in the west and flexure predominates in the east (Wagner, 1990). Reservoir quality in the field varies markedly from well to well and the sweet spots are found where fracture intensity and matrix porosity are greatest (e.g. Wagner, 1991; Horstman, 1987). Multiple reservoirs are suggested by

observations such as gas production down-dip to oil completions (Horstman, 1987). Giddings field, in 1988, contained 4500 Austin Chalk wells, for a field cumulative production of 209 MMBO and 934 BCFG (Durham and Bobigian, 1990).

Pearsall Field

Pearsall Field was discovered in 1935 by Amerada-Rycade. The first well was completed in the Austin Chalk and produced 2689 BOPD (Long, 1991). The field is located on the Pearsall Arch which is due to an early Mesozoic horst block created during rifting of the Gulf of Mexico (Long, 1991). The chalk is between 90 to 150 m (300 and 500 ft) thick, thinning over the Arch (Durham and Bobigian, 1990). Type logs for Pearsall Field are presented by Long (1991) and Durham and Hall (1991).

Long (1991) outlines the field's 58 year drilling history: (1) in 1940 the field contained 32 wells with an average cumulative of 80 MBO; (2) in the forties, wells were 'fractured' using either a nitroglycerin or acid treatment and average cumulative per well was 30 MBO; (3) in the seventies, hydraulic fracturing was used and wells averaged 40 MBO; and (4) in the eighties Sun, experimenting with lateral drilling, drilled the Sun #13 Baggett with an initial production of 1383 BOPD. Oryx drilled the first horizontal well in 1985. They established the standard wellbore azimuth as N60°W, generally perpendicular to the major set of fractures in the field (Bobigian and McDonald, 1991). By 1991, the field contained over 300 horizontal well completions with an average initial production of 500 BOPD (Long, 1991).

RESULTS

Utilizing FMS surveys, gamma ray logs, and electric logs from nearby offset wells, the subsurface Austin Chalk has been evaluated for: (1) orientation and spacing of fractures, (2) the relationship between log response and fracture density, (3) fracture density and its relationship to initial potential, and (4) relative fracture apertures.

Orientation

Methods

Orientation of fractures were mapped in seven widely spaced boreholes, five from the Giddings area and two from Pearsall. The true dip and strike of a fracture is calculated by the Fracview software on the basis of the sinusoid the operator places over a fracture trace (see Figure 31, Appendix A). Therefore, the better defined the fracture trace the more accurately can the operator define a sinusoid to fit the fracture and the more accurate the orientation. The orientation of fractures in the subsurface was of primary importance and therefore fracture picks were placed into one of four groups based on my confidence in the pick. These "confidence" groupings (CG) are a measure of how well defined is the fracture trace. (Refer to Appendix A for detailed descriptions of each confidence group.)

In order to interpret the fracture data it was necessary to establish how well an operator could reproduce the strike and dip of the fractures mapped from FMS data. As detailed in Appendix B, 90% of pairs of repeated strike and dip measurements are within 10° . Accordingly in the orientation data below, I elected to define a fracture set as having a deviation of $\pm 10^\circ$ in strike and

$\pm 10^\circ$ in dip. Accordingly, fracture concentrations would each have to be $> 20^\circ$ apart to be distinguished as separate sets.

Orientation - Overall

Over 9,000 fractures were mapped between the eight study wells. In each of the study wells only one set of northeast striking fractures is being identified in the subsurface (Figures 15 - 22). The stereograms illustrate that the fractures mapped in the subsurface are nearly vertical (fractures are mapped in upper-hemisphere, equal-area projection) and furthermore, the fractures are orientation within any given well is very consistent. The greatest diversity in strikes is associated with those wells where the CG Poor dominates the data set (e.g. 10653, 5105, 4790; Table 3). Within the confidence grouping Poor, strike direction may vary up to $\pm 30^\circ$ (e.g. Figure 18c.). The rose diagrams further emphasizes that only fractures striking NE-SW are mapped in the subsurface. Slight variations in strike with depth have been noted in some wells, as illustrated in Figure 23 (data includes all confidence groupings).

Notice that the strike of the fractures becomes more northerly moving from Brazos (Figure 15) to Zavala Counties (Figure 22) (Figure 24; Table 3). This swing in strike is similar to that noted at the outcrop by Corbett (1982) (Figure 14).

Orientation - Confidence Groupings

Orientation is very consistent for those fractures with confidence ratings of Good to Excellent (Figure 25). However, the range of strike and dip values broadens considerable as the confidence rating decreases from Good to Poor.

Figure 15--Orientation of fractures measured from FMS data, well 5288, Giddings Field, Brazos County. (A) Normals to 2222 fractures are plotted in upper hemisphere, equal-area stereographic projection the plane of projection horizontal and North as indicated; the black arrows indicate the mean azimuth of the borehole axis ($\sim 157^\circ$). (B) Rose diagram, from the same data, shows distribution of fracture strikes (5° cells) with the length of each cell normalized to that containing the greatest number of fractures. The majority of the 2222 fractures strike $N72^\circ E$.

(A)

(B)

Figure 16--Orientation of fractures measured from FMS data, well 10653, Giddings Field, Burleson County.
 (A) Normals to 1786 fractures are plotted in upper hemisphere, equal-area stereographic projection the plane of projection horizontal and North as indicated; the black arrows indicate the mean azimuth of the borehole axis ($\sim 159^\circ$).
 (B) Rose diagram, from the same data, shows distribution of fracture strikes (5° cells) with the length of each cell normalized to that containing the greatest number of fractures. The majority of the 1786 fractures strike N62°E.

Figure 17--Orientation of fractures measured from FMS data, well 10864, Giddings Field, Burleson County.
 (A) Normals to 1144 fractures are plotted in upper hemisphere, equal-area stereographic projection the plane of projection horizontal and North as indicated; the black arrows indicate the mean azimuth of the borehole axis (~168°).
 (B) Rose diagram, from the same data, shows distribution of fracture strikes (5° cells) with the length of each cell normalized to that containing the greatest number of fractures. The majority of the 1144 fractures strike N72°E.
 DEM ($\triangle$) and MF ($\square$) identify fractures mapped by Ms. McKiernan and Dr. Friedman, respectively.

Figure 18--Orientation of fractures measured from FMS data, well 5105, Giddings Field, Fayette County. (A) Normals to 1300 fractures are plotted in upper hemisphere, equal-area stereographic projection the plane of projection horizontal and North as indicated; the black arrows indicate the mean azimuth of the borehole axis (~165°). (B) Rose diagram, from the same data, shows distribution of fracture strikes (5° cells) with the length of each cell normalized to that containing the greatest number of fractures. The majority of the 1300 fractures strike N62°E. (C) Rose diagram, a subset from the CG Poor, shows that several different strike orientations are found within the CG Poor.

Figure 19--Orientation of fractures measured from FMS data, well 4790, Giddings Field, Gonzales County.
 (A) Normals to 507 fractures are plotted in upper hemisphere, equal-area stereographic projection the plane of projection horizontal and North as indicated; the black arrows indicate the mean azimuth of the borehole axis ($\sim 133^\circ$).
 (B) Rose diagram, from the same data, shows distribution of fractures strikes (5° cells) with the length of each cell normalized to that containing the greatest number of fractures. The majority of the 507 fractures strike N52°E.

(A)

(B)

Figure 20--Orientation of fractures measured from FMS data, well 15448, Pearsall Field, Zavala County.
 (A) Normals to 1133 fractures are plotted in upper hemisphere, equal-area stereographic projection the plane of projection horizontal and North as indicated; the black arrows indicate the mean azimuth of the borehole axis ($\sim 147^\circ$).
 (B) Rose diagram, from the same data, shows distribution of fractures strikes (5° cells) with the length of each cell normalized to that containing the greatest number of fractures. The majority of the 1133 fractures strike N42°E.

(A)

(B)

Figure 21--Orientation of fractures measured from FMS data, well 5451, Pearsall Field, Zavala County.
 (A) Normals to 199 fractures are plotted in upper hemisphere, equal-area stereographic projection the plane of projection horizontal and North as indicated; the black arrows indicate the mean azimuth of the borehole axis ($\sim 151^\circ$).
 (B) Rose diagram, from the same data, shows distribution of fractures strikes (5° cells) with the length of each cell normalized to that containing the greatest number of fractures. The majority of the 199 fractures strike $N52^\circ E$.

Figure 22--Orientation of fractures measured from FMS data, well 5639, Pearsall Field, Frio County.
 (A) Normals to 190 fractures are plotted in upper hemisphere, equal area stereographic projection the plane of projection horizontal and North as indicated; the black arrows indicate the mean azimuth of the borehole axis ($\sim 171^\circ$).
 (B) Rose diagram, from the same data, shows distribution of fractures strikes (5° cells) with the length of each cell normalized to that containing the greatest number of fractures. The majority of the 190 fractures strike N65°E.

Table 3. Summary of Results by Well.

Well	Location	Appr. Vertical Depth TAC	Total Fractures	Average Fractures Per Meter	Fractures Per Confidence Grouping	Orientation of Fracture Set	Angle Between Borehole and Fracture Strike
5288	Brazos Ct. 6 mi E-NE of College Station	~9000 ft	2222	6.7	E= 69 G= 209 F=1188 P=756	N72°E	88°
10653	Burleson Ct. 11.5 mi NE of Caldwell	~7300 ft	1789	2.7	E=35 G=50 F=111 P=1563	N62°E	86°
10864	Burleson Ct. 9 mi SE of Caldwell	~8600	1131	3.2	N/A	N72°E	83°
5639**	Fayette Ct.	N/A	190	--	--	N65°E	73°
5105	Fayette Ct. 5 mi NE of Winchester	~9200	1300	2.5	E= 3 G= 3 F= 114 P= 1181	N62°E	80°
4790	Gonzales Ct. 9 mi NE of Gonzales	~7600	507	N/A	E= 0 G= 0 F= 23 P= 484	N52°E	82°
15448	Location not available	N/A	1138	2.4	E= 17 G= 92 F= 402 P= 427 AOP= 200	N41°E	77°
5451	Zavala Ct. 10 mi N of Big Wells	~5700	199	.88	E= 3	N53°E	82°

*E=CG excellent, G=CG good, F=CG fair, and P=CG poor. AOP= accuracy of pick, this is data from the study done on the reproducibility of data. Where data is not available it is noted as N/A. ** Well 5639 was not analysed for fracture spacing. It was sampled only for a possible NW-SE fracture set.

Figure 23--Descending the borehole of well 5451, a change in strike, from N53°E to N42°E, is noted. Notice that variations of strike in each rose diagram increases as the data set (n) gets smaller.

Figure 24--Rose diagrams of fracture assemblage in each of the seven wells studied show there is a swing in fracture orientation from NE to SW along the Austin Chalk productive trend. Fracture orientations shift from N72°E in Brazos Ct. to N41°E in Zavala Ct.

Figure 25--Confidence groupings for well 10653, Giddings Field. Excellent, Good, Fair, and Poor refer to the confidence with which the fracture pick was made (see Appendix B). As the confidence in the pick decreases, the scatter in the orientation of the picks increases.

Spacing

Fracture spacing in the subsurface is defined herein as the linear distance between the nominal depths of adjacent fractures, regardless of orientation. (As such, this fracture spacing is identical to that measured along horizontal scanlines on the outcrop.) These spacing values are then grouped into 6 cm (2.36 in) cells (i.e. 0 to 6 cm, 6 to 12 cm, 12 to 18 cm etc.). The number of fractures in each cell is divided by the total number of fractures in the borehole, added to the cell below, and plotted at the center point of the fracture spacing cell (i.e. 3 cm, 9 cm, 15 cm, etc.) to obtain a percent cumulative fracture versus fracture spacing plot (Figure 26) similar to the one established for the outcrop (Figure 13). The minimum fracture spacing recorded from the FMS data is 3 cm. This is an arbitrary and conservative cut-off distance consistent with the ability to clearly resolve individual fractures in the FMS images. (Note: This cutoff was not needed at the outcrop, where fractures much closer than 3 cm were counted.) At the other extreme, all fractures spaced greater than 80 cm are placed in one cell. In some cases, this large spacing occurred because of gaps in the FMS data; for others the large spacing is real in that the FMS survey is of good quality and long unfractured intervals are seen. Six of the eight FMS surveys were evaluated for fracture spacing (well 4790 was not evaluated due to the poor quality of the FMS tape; well 5639 was not used for spacing data, see Table 3).

Well 10864 has a fracture spacing distribution which is nearly identical to that of the outcrop (Figure 26). The remainder of the curves lie below the curve representing the outcrop data. Further, except for well 5451, over half the fractures in each of the other wells are spaced < 20-cm apart.

Figure 26--Plot of fracture spacing against the percentage of cumulative fractures from outcrop data (■) and FMS data for six boreholes. The outcrop data are from 14 scanlines placed horizontally along vertical exposures at localities from SE of Del Rio to Dallas, TX.

Gamma Ray and Fracture Intensity

Corbett et al (1987) established a correlation between clay content and the relative brittleness of the chalk, with brittleness decreasing with increasing clay content. Gamma ray logs being sensitive to clay content (among other things) might, therefore, provide the means to predict the brittleness of a chalk interval. Lower gamma ray values should correspond to greater fracture intensity (i.e. fractures per linear foot) and vice versa. The majority of the FMS surveys also have a gamma ray track. It was therefore possible to examine the relationship between gamma ray values and fracture intensity along the borehole. A plot of fractures per foot versus gamma ray value (Figure 27) shows much scatter but suggests a general relationship between higher fracture intensity and lower gamma ray values particularly for gamma ray values > 30 API units. Note that fracture intensity is nearly independent of gamma ray values of 20 ± 10 .

Observations of fracture intensity and gamma ray values in individual wells are as follows:

Well 10864: The majority of the well has a fracture intensity of > 13 frs./m (4frs./ft). Gamma ray values are mostly under 30 API units.

Well 5288: Fracture density is quite high in this well in comparison to the other wells (averages ~ 8 fractures per foot). The gamma ray are about 45 API units. Fracture intensity increases with a decrease in the gamma ray value and is greatest when the gamma ray is ≤ 30 API units.

Well 10653: Fracture intensity is between 4 and 10 fractures per meter 1.2 -3 frs./ft) for most of the borehole. Gamma ray stays fairly consistently at 30 API units. Increased fracture intensity corresponds to decreases in gamma

Figure 27--Plot of gamma-ray values versus fractures/ft from FMS survey, well 15448, Austin Chalk, Pearsall Field, South Texas. Each data point represents the average of these two parameters in a 10 ft interval along the borehole.

ray value. When gamma ray exceeds 45 API units there is no evidence of fracturing.

Well 4790: Fracture intensity plots along borehole were not made due to poor FMS quality.

Well 15448: Fracture intensity is up to 26 frs./ft (8 frs./ft) between measured depths (MD) of 2103 to 2195 m (6900 and 7200 ft) with gamma ray values of between 15 and 30 API units. Fracture intensity decreases to 10 frs./m (3 frs./ft) from 2240 to 2316 m (7350 to 7600 ft) for which gamma ray values average 25 API units. Between 2865 and 2987 m (9400 and 9800 ft) gamma ray values are < 30 API units and the fracturing is between 3 to 10 per meter (1 and 3 per foot).

Well 5451: The borehole of this well is only slightly fractured, averaging one fracture per foot with a high of 16 frs./m (5 frs./ft). Gamma ray also is relatively low throughout the interval, about 15 API units with hot streaks of up to 95 API units.

In summary, except for well 5451, fracture intensity generally increases when gamma ray values decrease.

Initial Potential and Fracture Intensity

Productivity of a well in a fractured reservoir will be a function of, among other things, the number of fractures intersected by the borehole. The number of fractures for a borehole was divided by the total footage of measured fractured borehole (not the total footage of the borehole) to obtain an "average" linear fracture density (frs./ft). This value was then plotted against the initial potential of the well (Figure 28). As expected, a positive linear slope relates increased fracture intensity with larger initial potential values.

Figure 28--Plot of initial potential against "average" fracture density (see Text) for 5 wells. Least-square line shows the overall trend. Initial potential values taken from Petroleum Information reports.

Aperture

Two types of aperture values are calculated in the Fracview software, mean aperture and hydraulic aperture. The mean aperture value is a measure of the size of the fracture and is simply the arithmetic average of the fracture width. Hydraulic aperture is the cubic mean of the fracture width and is, therefore, proportional to the fluid flow through the fracture. Aperture values for one well cannot be compared to aperture values of another well unless the resistivity values for each well have been calibrated and the resistivity of the mud is known. While it was not possible to calibrate the wells with respect to highest and lowest formation resistivity, it was possible to manipulate mud resistivity such that the smallest aperture value for any well is normalized to .006 mm. In this way aperture values can be compared within and among wells. This low-end aperture value represents the limits of the tool resolution (D. Thorn, 1992, personal communications). Table 4 summarizes aperture values for the majority of the fractures (i.e. > 98%) in the study wells. In some wells, a gradual increase in aperture corresponds to a decrease in fracture density (Figure 29).

Table 4. Range of Hydraulic Aperture Values Seen in the Study Wells.
Aperture Values Have Been Normalized to 0.006 mm (See Text).

Well	Aperture (mm)	Comments
10864	0.01 - 0.1	9075' to TD change to 0.1 - 1.0
10653	0.01 - 0.1	
5288	0.01 - 1.0	
5105	0.01 - 1.0	
15448	0.03 - 1.0	zone of low apertures (0.01 - 0.1)
5451	0.01 - 1.0	over 80% between 0.1 - 1.0 mm

Figure 29--A gradual increase in aperture value corresponds to a decrease in fracture density.

DISCUSSION

Fracture Orientation

General Result

Fracture orientation in each of the eight FMS study wells is characterized by the development of only one set of NE striking fractures (Figures 15-22). This fracture pattern is much simpler than that seen at the outcrop where at least a NW-SE cross-trending set exists.

The simpler fracture pattern observed in the subsurface may result from a "blind spot" inherent in the determination of fracture data from boreholes (e.g. Friedman, 1969). That is, fractures nearly parallel to the horizontal borehole are not only insufficiently sampled, unless closely spaced, but also are difficult to recognize in the FMS survey as they would appear along only two of the four pads. Therefore, equal sampling of orthogonal fracture sets requires that the azimuth of the borehole axis be 45° from the strike of the fractures.

Unfortunately most slant or horizontal wells are drilled sub-normal to the NE-SW fracture set. None-the-less, if the angle between the borehole axis and the fracture strike is $< 80^\circ$ the opportunity exists to sample a cross-trending fracture set. The amplitudes of the cross-trending fractures would, however, be highly elongated and therefore are not as straightforward to identify. As noted in Table 3, the angle between the borehole axis and the mean fracture strike ranges between 88° and 72° . In each well, the possibility of a cross-trending (NW-SE) fracture set was investigated by determining the shape of the corresponding sinusoidal trace and with this shape in mind scrutinizing the borehole image for events which might fit this sinusoid. In addition, the borehole axis wanders somewhat throughout the length of the borehole, up to

25°, and the wandering of the borehole axis would provide an opportunity for a cross-trending fracture set to be mapped. In spite of these considerations, very few fractures parallel to a NW-SE cross-cutting set were detected.

There is enough scatter in the fracture data to feel confident that the NW-SE fractures could have been mapped had they been present. Notice that in well 10864 a handful of events strike NW-SE, although not enough of these events are identified to make them statistically relevant. From the standpoint of addressing the sampling bias the best wells are 5639 and 15448. The strongest concentrations of fractures on both wells strike NE-SW (Figures 20, 22). I feel that the sampling bias issue has been well addressed not only by seeking out boreholes with low borehole axis angle with respect to fracture strike, but also by recognizing the sinusoidal shape within each borehole which would characterize fractures striking NW-SE.

Accordingly, the conclusion that the only strongly developed fracture set in the subsurface is nearly vertical and strikes NE-SE seems warranted.

A further concern in evaluating fractures from the FMS is the inadvertent mixing of drilling induced and natural fractures in the analysis. Particularly suspect are fractures oriented perpendicular to the regional least principal stress (σ_3). Assuming σ_3 is parallel to the dip of the beds, then along the Austin Chalk play these induced fractures would also strike NE-SW. Such fractures might be induced by hydrofracturing the borehole rocks during inadvertent mud pressure surges. Personal communications with operators in the trend (Thom, 1992; Svor, 1993) suggest that drilling induced fractures are not of major concern. Moreover, Fett (1992, personal communications) states that those few induced fractures that do occur are exactly perpendicular to the borehole axis. If Fett is correct, then such induced fractures should occur (a)

along the bend of the borehole as it goes from vertical to horizontal as well as (b) along its horizontal trace regardless of the angle between borehole axis and orientation of sigma 3. I see none of (a) and the great majority of normals to the fractures forming the NE-SW striking set make an angle of up to 20° with the azimuth of the borehole (black arrows on the stereograms indicate the borehole azimuth in Figures 15-22).

Kinlaw Oil Company made available an analysis of fracture orientations from the B-1 Newsom, a horizontal well in Pearsall Field, Frio County (Grier and Malek, 1991). Fractures in 424 feet of oriented core were mapped and classified as natural or induced. Of the 957 fractures identified, 93% were considered natural fractures. Hydrocarbon staining, calcite lining, and high-angle dips were used as the criteria to distinguish natural fractures from "induced" fractures. Admittedly factors influencing induced fractures in the core may be quite different from those producing fractures on the walls of the borehole.

In summary, one set of vertical fractures trending NE-SW are identified in the subsurface with minimal scatter and no cross-trending set evident. As discussed above, the weight of the evidence suggests that potential sampling problems due to a "blind spot" and/or the inclusion of induced fractures do not alter the overall conclusions.

Supporting Data

UPRC has drilled over 500 horizontal wells in the Austin Chalk and is arguably the most successful operator in the trend. In UPRC's experience (N. Meehan and R. Svor, 1992-93, personal communications) the dominate fracture set strikes NE-SW. In addition to their own FMS data they cite well

interference patterns as evidence for a single fracture set. Wells which are offset along fracture strike are in pressure communication; wells which are aligned normal to fracture strike, however, are not. This empirical observation suggests that a pervasive cross-trending fracture set does not exist.

Schlumberger (Fett, 1991) also reports that drilling, stimulation, and production point to good communication to the NE-SW and poor communication to the NW-SE.

The core report on the B-1 Newsom (Grier and Malek, 1991) shows one set of natural fractures oriented normal to bedding and striking NE-SW. The strike of the fractures is consistently between $N30^{\circ}$ - 50° E. This orientation corresponds to those found in the study wells of Zavala County (see Figure 23; Table 3).

Snyder and Craft (1977) provide a summary report of core and fracture analysis done in the Austin Chalk. The core analysis indicates that a single set of fractures exists in the Austin Chalk. Furthermore, this report indicates that the best fractures are found in low porosity zones of "hard" chalk.

Schnerk and Madeen (1990) also report that fractures in a horizontal core, from Pearsall Field, are vertical and trend to the NE-SW. In addition, they report that the dominant fracture set in Giddings Field strikes NE-SW and that production in this field is enhanced by the local development of a cross-trending fracture set.

Conflicting Views

Outcrop studies (e.g. Corbett, 1982; Collins et al., 1991) identify two well developed cross-trending fracture sets striking NE-SW and NW-SE as well as other sets of fractures genetically related to local structure (e.g. normal faults,

plunging anticlines, and graben-in-graben). Subsurface studies of fracture orientation by Corbett (1982) and Thornhill (1982) indicate that two cross-trending fracture sets also can be found in the subsurface. Using oriented vertical cores from Brazos and Frio Counties, and FILs (four-arm dip meter data) from Lee and Burleson Counties, Corbett found two sets of cross-trending fractures, one parallel to bedding strike and the other parallel to bedding dip. Over 259 fractures were measured in the cores, 56% striking NW-SE and 41% striking NE-SW. Only 56 fractures were identified on the FILs, the most commonly developed orientation NW-SE. Thornhill identified two sets of cross-trending fractures in the subsurface on the basis of surface drainage patterns, FILs, and contoured initial potential maps. Thornhill reports, however, that the NE-SW orientation is the strongest throughout his study area which includes Fayette and adjoining counties.

Origin of Fractures

The conclusion that the subsurface fracture pattern is simpler than that of the outcrop is not an observation unique to the fractured Austin Chalk. Lorenz and Hill (1991) report that in naturally fractured Mesaverde reservoirs the outcrop has a well-developed cross-trending fracture set not seen in the subsurface. The cross-trending fractures seen at the outcrop probably include many fractures related to stress release during uplift, erosion, and exposure. In the main, fractures at the outcrop and in the subsurface are extensional fractures oriented normal to bedding and the least principal compressive stress (σ_3). It is generally accepted that regional fracturing in the Austin Chalk is influenced by regional extension related to subsidence into the Gulf of Mexico. Typically extension fractures are symptomatic of very brittle deformation.

In the subsurface, a condition under which only one set of vertical extension fractures would form is plane strain. Conditions of plane strain could be achieved if σ_1 is equal to the overburden (σ_v), σ_3 is equal to the minimum horizontal stress (oriented parallel to the regional dip direction), and σ_2 is equal to the maximum horizontal stress (parallel to the strike of bedding) and strain is accommodated only in the dip direction.

Local variations in dip (local structure) would also influence the development of fractures. For example, in Pearsall Field fracturing is believed to be due to differential compaction over a Mesozoic horst block (Long, 1991). Along the southern end of the field, subsidence into the Gulf enhances fracturing. These fractures strike NE-SW. In addition, along the nose of the arch a NW-SE fracture set is found. Corbett et al. (1991a) found that, in the field, plunging anticlines are characterized by three sets of fractures: (1) the earliest, longest, and most widely spaced are normal to bedding and parallel to the fold axis; these are accompanied by (2) a cross-cutting somewhat younger set perhaps typical of folded beds (Stearns and Friedman, 1972), and (3) short, curved, and randomly oriented fractures that are the last to form.

The diffusely oriented fractures associated with the confidence grouping (CG) Poor are implicitly smaller than the fractures of the other groupings (hence the difficulty in defining the fracture trace). Perhaps these fractures act as a network connecting the larger more systematic fractures, and may correspond to the third group of fractures recognized in outcrop.

Fracture Spacing

General Statement

One of the more interesting and surprising results of this study is that the frequency distribution of fracture spacing in the subsurface mimics that measured at the outcrop (Figure 26). The outcrop spacing data serves, therefore, as a minimum-spacing boundary curve or model.

In comparing the outcrop and subsurface fracture-spacing data, outcrop fractures spaced closer than 3 cm were included in the data set whereas in the analysis of the FMS surveys fractures spaced closer than 3 cm were not included, as explained on page 50. Accordingly, the smallest-spaced cell for the outcrop data contains many more fractures than that in the subsurface. Fractures were counted regardless of their orientation for both the outcrop and the subsurface.

Supporting data

Snyder and Craft (1977) report an average fracture spacing of 10 cm (1 to 3 per foot) from vertical core analysis. Similarly in horizontal core, spacing within "fracture swarms" is found to be as high as 3 fractures per foot (Schnerk and Madeen, 1990). These observations coincide well with the fracture spacing curves in Figure 26, the 10 cm spacing falling within the second-smallest fracture spacing cell.

Ramifications

In nearly all cases, >50% of the fractures are spaced closer than 20 cm (8 in). The exception to this is well 5451 where >50% of the fractures are spaced ≥ 40 cm (1.31 ft) apart. In addition to being useful in the development of models of

fluid flow in chalk reservoirs, these spacing data also relate to the origin of the fractures.

The spacing of regional fractures ranges widely from just under 0.3 m to 6 m (1 to 20 ft) apart (Nelson, 1985). In the Austin Chalk, the systematic fracture set averages one every 60 to 90 cm (2 to 3 ft) (Corbett and Hung, unpublished data). This correlates closely to spacing of regional fractures in the naturally fractured Mesaverde reservoir which averages 46 cm to 1 m (1.5 to 3.4 ft) (Lorenz and Hill, 1991).

The implication of small fracture spacing as noted above is that local tectonic events superpose additional and similarly oriented fractures on the regional fractures. Supporting this conclusion are studies by Corbett et al. (1991a) and Collins et al. (1992) which show fracture intensity increasing with proximity to local structure.

Nelson (1985) notes that the best fractured reservoirs will be those that have tectonic fractures overlying regional fractures. The example given above (Long, 1991) of the fracture development over the nose of the Pearsall Arch supports Nelsons' statement as that portion of the field is the location of the best production. The fracture-spacing data presented herein indicates that the NE trending fracture sets in the Austin Chalk may be composed of both tectonic and regional fractures.

Extrapolation of Outcrop Data to the Subsurface

Orientation

A comparison of Figures 14 and 22 illustrate that in outcrops between Uvalde and Waco the NE-SW set strikes $N39^{\circ}E \pm 17^{\circ}$, and the strike in the subsurface is $N57^{\circ}E \pm 17^{\circ}$. Further, comparison of outcrop data to the closest

FMS study well yields the following observations: In San Antonio the strike direction is $N45^{\circ}E$, this is comparable to the subsurface strike found in well 5639 (Frio Ct.) of $N65^{\circ}E$ and well 4790 (Gonzales Ct.) of $N42^{\circ}E$. The outcrop data from Austin is closest to the Gonzales well (4790) and the Fayette well (5105). Here fractures on the outcrop strike of $N55^{\circ}E$ whereas in wells 4790 and 5105 the fractures strike $N52^{\circ}E$ and $N62^{\circ}E$, respectively. The Brazos County well (5288) is closest to the Waco outcrop. A strike of $N22^{\circ}E$ is recorded on the outcrop and $N72^{\circ}E$ is recorded in the subsurface. The dip of the fractures both at the outcrop and in the subsurface are between 90° and 80° .

The data base for this study did not include structure maps, seismic lines, nor structural cross-sections and therefore there is no way for me to make any meaningful conclusions as to why these strike variations occur vis-a-vis possible local structure. However, since outcrop and subsurface strikes for the NE-SW trending set vary up to 20° , there is validity in using the outcrop as a first estimation of potential fracture trends in the subsurface. The question then is, which of several fracture sets on the outcrop is most likely to dominate in the subsurface? For the Austin Chalk play it can be argued that the NE-SW striking fracture set is apt to be the best developed in the subsurface because such fractures are: (1) often the most continuous (longest and most deeply penetrating) on the outcrop (Corbett et al., 1991a), (2) are genetically consistent with the orientations of fractures associated with local structure, and (3) are oriented perpendicular to the regional down-dip extension that characterizes the Gulf Coast basin.

Spacing

The average fractures per meter increases to the north along the producing trend in the subsurface (see Table 3). This does not correlate with Corbett's observation which showed decreasing fracture density to the north along the outcrop trend. The depositional environment of the chalk to the north is deeper and more shales are associated with the chalk, and therefore the chalk would be considered weaker than chawks from shallower environments (for example along the San Marcos Arch, where not only are the chawks cleaner they are thinner). My data suggest, however, that fracture density in the subsurface chalk is greatest in this basinal regime. Factors which could influence fracture density include porosity, clay content, proximity to local structure, and stratigraphic location of the borehole axis.

In Figure 9, the hypothesis was put forth that for deformation in the brittle regime the stronger rock would be more highly fractured than the weaker one. Indeed this idea is supported by the correlation of higher fracture density and lower porosity in the chalk (i.e. Snyder and Craft, 1977). However, if in the basinal regime the differential stress was not great enough to break the strongest rock it would be the weaker rock which would fail and exhibit the greatest intensity of fracturing. Laboratory experiments of specimens consisting of alternating layers of relatively weak chalk between relatively strong chalk, loaded such that σ_1 was normal to the bedding, show that at low differential stresses the weaker chalk fractured while the stronger chalk was unaffected at least macroscopically.

Initial Potential and Fractures/Foot

In low-porosity, low-permeability, naturally fractured reservoirs the natural fractures are the conduits for fluid migration. Therefore, other factors being equal, a positive linear correlation between initial potential and fracture density would be expected and is indeed suggested by Figure 28. Points which plot above the least-square line are perhaps from locations where the fractures are effective conduits. Points below the line can be explained in several ways: (a) not all the fractures counted may actually produce, (b) the matrix may not have expelled the hydrocarbons yet (should correlate with resistivities of the deep induction greater than 40 ohm-m), and (c) two or more wells producing from the fracture network.

Aperture Values in the Subsurface

Aperture values were compared between wells by normalizing the smallest aperture value to .006 mm (see p. 55). The range of aperture values for the seven wells is consistently 0.01 to 1.0 mm. This aperture range is consistent with that reported by Corbett (1982) and Snyder and Craft (1977), but it is quite a bit larger than would be expected at depth. Nelson (1985) reports a range of 0.01 to 0.5 mm for depths < 5,000 ft.

No obvious correlation between mean aperture value and initial potential could be found in my study wells. Svor and Meehan (1991) developed a method of rating fractures on the basis of the magnitude of the resistivity of a fracture in comparison to some standard resistivity value (resistivity being a direct measure of the aperture within the FMS technology). The fractures are then rated excellent to poor on the basis of their aperture value and weighted to calculate a fracture index number. This fracture index number is then

compared to the total fluid Productivity Index during the first 10,000 bbl of fluid production. They report a good correlation between the two indices.

Gamma Ray versus Fracture Intensity

Ductility increases and strength decreases with increasing clay content. Assuming that gamma ray is a direct measure of clay content, a correlation between gamma ray and fracture density is anticipated. Empirically, fracture intensity increases when gamma ray decreases (see Figure 30), although an increase in gamma ray is not necessarily associated with a decrease in fracture density. These observations were made from FMS produced logs plotting fracture density and gamma ray against depth. "Low" gamma ray values are considered those < 30 API units while "high" gamma ray values are those >30 API units. The plot of fracture density versus gamma ray shows a tremendous amount of scatter (Figure 27). Several explanations for the scatter can be put forth. For example, when gamma ray is low and fracture intensity also is low the most obvious explanation is that fracturing is due to regional stresses rather than tectonic (hence the low intensity). When high gamma ray values are associated with a high intensity of fracturing the high gamma ray value may be caused by factors other than that of increased clay content. For example, if the resolution of the gamma ray is such that the gamma ray is averaged over several feet of section, interbedded clay layers would greatly effect the resulting gamma ray readings. Another possible explanation, might be the concentration of uranium, leached from interbedded bentonite beds, within existing fractures by waters percolating through the formation. Deposition of the uranium on the walls of the fractures could then explain anomalously high gamma ray values. Notice that below 20 API units fracture intensity is

Figure 30--Fracture density (curve on the right) increases as gamma ray (curve on the left) decreases. Example taken from well 5288.

completely independent of gamma ray (Figure 27). An explanation for the scatter associated at this end of the plot may be proximity to local structure.

CONCLUSIONS

The major conclusions warranted from this study are:

1. A single set of northeast striking fractures is mapped in the subsurface; this is a significantly simpler pattern than that of the outcrop.
2. The outcrop spacing frequency distribution curve acts as a minimum-spacing-boundary curve, equaled in one of the subsurface wells, but generally above the subsurface spacing curves from the other wells. Greater than 50% of the fractures in both the subsurface and at the outcrop are spaced ≤ 20 cm apart.
3. The spacing data indicate that a regional NE striking fracture set is enhanced by similarly oriented tectonic fractures genetically related to local structure (e.g. a normal fault striking NE-SW).
4. Extrapolation of outcrop strike values for the systematic NE-SW trending set to the subsurface is reliable within $\pm 20^\circ$.

Also warranted are the following conclusions:

1. The FMS and the accompanying interpretation software, Fracview, provide a comprehensive view of subsurface fracture patterns. In addition the software provides a means to qualitatively measure anisotropies in the reservoir, for example a preferred fracture orientation. However caution must be used. Aperture and fracture porosity results, for example, have no quantitative value unless the image resistivities are calibrated. Further, in the evaluation of the subsurface fracture pattern, fracture patterns on the outcrop should be kept in mind and potential "blind spots" (i.e. for fractures parallel to the borehole) recognized.
2. Further investigation is needed to understand factors influencing fracturing in the subsurface. Figure 27, for example, illustrates that the relationship

between gamma ray and fracture density is not straightforward. Clarification and calibration of this relationship is needed. In addition, the spacing data suggests tectonic influences affect fracture density (and potentially orientation as well), therefore it is necessary that local structural controls are better defined. This would require seismic lines and/or structural cross-sections through the area of the FMS survey.

Providing a comprehensive and detailed "mechanical stratigraphy" for the Austin Chalk reservoir will require an understanding not only of the effects of local structure but also of local and regional variations in lithology.

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APPENDIX A

The Formation MicroScanner (FMS) is a microresistivity device designed to record and map features in the subsurface such as bedding planes, fractures, faults, and sedimentary features. The FMS works essentially like a dipmeter. Four pads, oriented at 90° intervals and containing small button-like electrodes, record an image of the borehole wall by mapping relative changes in electrolytic conduction (Bourke et al., 1989). An accelerometer and a magnetometer are used to determine the true position and orientation, respectively, of the tool at all times. The tool has high vertical resolution, samples are taken every 2.5 mm (0.1 in), and it is sensitive to a large dynamic range (0.1 to more than 10,000 ohm-m) (Serra, 1989). The resistivity measurements are turned into images by assigning the highest resistivity measurement the color white and the lowest resistivity measurement the color black. The remainder of the resistivity values are accorded a color scaled between this high and low resulting in a variable-intensity gray or color image. Fluid-filled fractures and conductive beds are recorded as low resistivity anomalies (Figure 31). Details about the function of this tool and its major applications are given by: Bourke et al., 1989; Serra, 1989; Cheung and Heliot, 1990; and Svor and Meehan, 1991a.

FMS images are interpreted utilizing a SUN/SPARC workstation and Schlumberger's Fracview 1.2 software. The software is a comprehensive program which enables an operator to, among other things, select planar events (e.g. fractures), record their true strike and dip, and categorize the events into groups (specified by the operator). These data can then be displayed on stereonets and/or rose diagrams and possible trends (e.g. strike

Figure 31--Fluid-filled fractures and conductive bedding planes appear as dark, low resistivity events. This picture is taken where the borehole deviates 65° ; as the borehole deviation approaches 90° (horizontal), the amplitude of the nearly horizontal bedding plane sinusoids becomes very large. Examples of each of the four confidence groupings (excellent, good, fair, and poor) are identified (see Appendix A).

variations vs. depth, aperture value vs. depth, etc.) can be explored by including (or excluding) chosen events into any number of groups or subgroups as designed by the operator. Furthermore, a group-statistics-panel records such items as the mean azimuth and mean dip of the events in the group. Attributes such as aperture, trace-length, fracture porosity, planarity, and density (i.e. events per linear distance) can be plotted against a measured depth scale. The inclination and deviation of the borehole also can be plotted against a measured depth scale, as can gamma ray logs, when available. To facilitate visualization of the relationship between chosen events and the borehole, the software provides a 3-D image of the borehole. The raw data also can be displayed as the raw resistivity curves.

The method used here to analyze the fractures, while independently derived, is similar to that of Cheung and Heliot (1990) as follows:

(1) Fluid-filled fractures and conductive beds (shales/marls) both appear as low resistivity events but are easily distinguishable by the shape of the feature. In horizontal boreholes, nearly vertical fractures appear as low-amplitude events while nearly horizontal bedding planes are high-amplitude events (Figure 31) (vice-versa in vertical holes). Fractures are mapped in Fracview at a scale of 1:5 (horizontal) and 1:10 (vertical).

(2) Fractures, once picked, are placed into one of four confidence groups as defined by the operator. The four confidence groups were defined as follows (see examples, Figure 31): (a) Excellent fractures are those whose trace appears on 3 to 4 pads. The trace of the fracture is conspicuous and includes the full sinusoidal shape. These events could actually be several reasonably parallel, closely spaced fractures that, because of limits in tool resolution, are recorded as one feature; (b) Good fractures are those whose trace appears on

2 to 4 pads with the trough and peak of the sinusoid present; (c) Fair fractures are those whose trace appears on only two or three pads and at least a small portion of the trough and peak of the sinusoid is present; and (d) Poor fractures are those whose trace appears on only one or two pads and whose orientation is suspect because the trough (or peak) of the sinusoid is not identifiable.

(3) A dip attribute file, including all the above groups, is made to gather the nominal depths of the fractures to be used when determining fracture spacing (see p. 49).

(4) Orientation data are plotted in upper-hemisphere, equal-area projection and/or as rose diagrams to identify the fracture pattern.

(5) Fracture density along the borehole is plotted against measured depth as well as gamma ray.

(6) Hydraulic aperture is plotted against depth.

(7) Consideration is given to the recognition of a cross-trending fracture set. A template sinusoid, characterizing the shape of the cross-trending fracture, is made and the borehole image scrutinized for possible features fitting this template.

This basic procedure was followed for each well in the study.

APPENDIX B

The reproducibility of fracture orientation data was investigated early in the study to determine the degree to which one might discriminate one, two or more closely oriented fracture sets. The strikes and dips of 200 fractures were mapped with Fracview. The picks were then erased and the same fractures mapped a second time. The differences between these pairs of strikes and dips were then plotted against the number of comparisons in percent (Figure 32). The study indicates that my reproducibility is such that 97% of the paired dip values and 90% of the paired strike values differ by $< 10^\circ$. Therefore, on stereograms or rose diagrams of strike or dip direction, one cannot distinguish between one fracture set and another unless the centers of their concentrations are at least 20° apart.

A

B

Figure 32--The differences in dip between pairs of picks of a fracture trace (A) are plotted against the number of comparisons in percent. The data suggest that my reproducibility is such that 97% of the repetitions differ by $< 10^\circ$. (B) shows the difference in strike between comparisons; 90% of the comparisons differ by $< 10^\circ$.

APPENDIX C

One of the primary objectives of this thesis was to take initial steps in the development of a detailed structural stratigraphy for the subsurface. Working within the gross structural-stratigraphic framework as outlined by Corbett et al. (1987), I envisioned being able to further subdivide the chalk into mechanical units based on comparison of fracture intensity, as mapped in the horizontal boreholes (Figure 33), relative to stratigraphic position. In addition, these mechanical units would be correlated to gamma ray and resistivity log character in order that these logs could be used independent of FMS to predict zones of fracturing. The initial approach taken to achieve this goal and the problems encountered are outlined below.

The stratigraphic position of the horizontal borehole is located on an electric log from a nearby vertical well by "hanging" the borehole trajectory profile on the base of the Austin Chalk; making the assumption that the base of the Austin Chalk occurs at the same depth in the horizontal and vertical well. Once the stratigraphic positions of the horizontal wells are determined then comparisons between stratigraphic position and fracture intensity along the borehole can be made and a detailed fracture stratigraphy established.

Profiles of the borehole trajectories are made using either true or estimated vertical depths and calculated horizontal displacement. When true vertical depths are not available from Petroleum Information they are calculated from the measured depth along the borehole. Along the horizontal borehole, every 25 or 30 feet, the angle of inclination and corresponding measured depth are noted. Using trigonometric relationships the vertical and horizontal distance between any two points along a borehole can be calculated. A

Figure 33--Fracture density along well 5105, Giddings Field. Fracture intensity is greatest in the first third of the well. Scale 1"=500".

measured depth from a nearly vertical section of the borehole (inclination $<10^\circ$) is used as the starting depth to which the calculated vertical and horizontal distances are then summed. For example, the vertical distance between measured depth 2500 and 2600 at 20° inclination is 41 ft and the horizontal distance is 91 ft. If the measured depth at 5° inclination is 2400 ft, then a calculated true vertical depth of 2441 corresponds to a measured depth of 2500 and the horizontal displacement from vertical is 91 ft.

True vertical depth is not the same as true stratigraphic depth.

Therefore the assumption that the depth of the base of the Austin chalk in the vertical well corresponds to the same depth in the horizontal borehole is not valid. The true vertical depth will differ from the true stratigraphic depth by some amount depending on the dip of the beds and the laterally distance between the two wells. If the horizontal well is downdip to the vertical well then the true vertical depth is greater than the stratigraphic depth and vice versa if the horizontal well is updip of the vertical well.

Since the spatial relationship of the vertical and horizontal boreholes were not known and further, no structural maps were available for this study, it was not possible to locate the horizontal boreholes stratigraphically and therefore I could not take steps to the development of a fracture stratigraphy. In addition, operators in the Austin Chalk have already empirically divided the Austin Chalk into at least five structural units, therefore for our study to be of real usefulness a much more detailed study than that initially outlined would need to be undertaken. Not only would zones of relative brittleness need to be identified but they would then need to be correlated to changes in lithology, proximity to local structure, and productivity.

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