Don Remson

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AN ASSESSMENT OF THE RESERVE GROWTH POTENTIAL OF THE CLEAR FORK PLATFORM CARBONATE PLAY IN TEXAS

PREPARED FOR:

U.S. DEPARTMENT OF ENERGY/
OFFICE OF FOSSIL ENERGY

BY:

ICF RESOURCES INCORPORATED

AND

BUREAU OF ECONOMIC GEOLOGY
THE UNIVERSITY OF TEXAS AT AUSTIN

SEPTEMBER 1989

9300 Lee Highway
Fairfax, Virginia
22031-1207

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FOREWORD

This report is part of a coordinated series of research efforts designed to prepare preliminary evaluations of important components of the domestic unrecovered oil resource. The specific resource of interest is the oil that is displaceable by water and remains in the Nation's reservoirs after conventional production. Integrated geologic, engineering, and economic evaluations in this series estimate future reserve additions from this unrecovered mobile oil (UMO) resource under various circumstances. The individual studies (Volumes 2 through 5) consider the effects of changes in oil prices and advances in production technology on the economic recovery potential of the UMO resource. This report (Volume 1) discusses and compares the approaches and results of the individual studies. Several recovery technologies are evaluated, including the use of waterflooding in conjunction with infill drilling to displace and produce UMO at decreased well spacings.

The overall analysis series was conducted in two separate, but coordinated, parts: at a detailed reservoir level and at a generalized regional level. At the reservoir level, detailed analyses of three individual Texas reservoirs fully delineated the resource and the potential for UMO recovery in each reservoir under a variety of development situations. Results of the individual reservoir evaluations were extrapolated to groups of reservoirs with common depositional histories, collectively known as "plays". At the regional level, reservoirs in three major oil producing states, Texas, Oklahoma, and New Mexico, were analyzed to determine the resource volume, potential recovery, and the costs and benefits associated with this recovery both in the individual states and for the region as a whole. This analysis relied on the geologic classification of individual reservoirs, specific rock and fluid properties, and production and development histories to quantify the resource and to assess its potential for UMO recovery potential. Coordination of the studies at two analytical levels proved advantageous -- the initial methods and results at both levels were compared in order to calibrate and to modify the final approach at each level and can now be used as a guide in future analyses. In addition to the specific results from the two analytical levels, several shorter issue and summary papers have also been prepared.

The individual reservoir and regional analyses reached similar conclusions. The potential for additional production of the UMO resource appears to be established even at low oil prices.

At an oil price of $10 per barrel, many reservoirs could be developed to recover significant additional quantities of UMO, even at current levels of technology. However, full exploitation of the UMO resource hinges upon the emergence of efficient methods for characterizing reservoir heterogeneity which would allow accurate assessments of features such as internal architecture, flow paths and barriers to flow. Understanding and describing reservoir heterogeneity would enable the geological targeting of new wells in the most productive portions of the reservoir. Such geologically targeted drilling would increase oil recovery and would lower the oil prices necessary to implement individual projects. Research that refines UMO descriptive and recovery techniques plays a vital role in maximizing the economic production of the resource.

These analyses were conducted by ICF Resources Incorporated, under contracts with the U.S. Department of Energy. Dr. Jerry P. Brashear served as the director of the overall study series. ICF Resources activities were managed by Mr. Michael Godec, who was responsible for the detailed reservoir studies, and Mr. Alan Becker, who managed the three-state regional analysis. Mr. Vello Kuuskraa was the project director for the early development of the methodology and the initial analysis of the Dune Field, the first of the reservoir-specific studies (Volume 2). The Bureau of Economic Geology (BEG) at the University of Texas at Austin served as the principal subcontractor for all analyses, providing critical geologic interpretation, data review, and expert consultation on the analysis and the interpretation of results. Dr. Noel Tyler directed the BEG efforts on these projects.

The staffs of ICF Resources and BEG performed the technical evaluations for the analyses in this series. Mr. Matt Parsley, Mr. Don Remson, and Mr. Jay Rushing of ICF Resources provided critical technical expertise in developing, modifying, and utilizing the methods for analyzing UMO at the reservoir and play levels (Volumes 2, 3, and 4). Ms. Kathleen McFall provided technical evaluations for the early development of the methodology and the initial analysis of the Dune field and South Central Basin Platform Play (Volume 2). Mr. Khosrow Biglarbigi and Mr. Hugh Guinn, in ICF Resources' Bartlesville Office, were critical to the data preparation, methodology development, model updates, and computer analysis completed in the three-state, regional analysis (Volume 5). Mr. Neil Cohen served as researcher for the regional analysis and editor of the final reports. The staff of BEG, including Mr. Bill Ambrose, Mr. Mark Holtz, Ms. Nancy Banta, Mr. Seay Nance, and Mr. Brad Stokes, provided timely and essential support for each of the analyses. Finally, the word processing efforts of Ms. Barbara Jones and Ms. Cheryl LaBrecque of ICF Resources were crucial to the preparation of the reports in this series.

The analyses relied substantially on the data and models that make up the Tertiary Oil Recovery Information System (TORIS). Use of the reservoir information in the TORIS data base was instrumental in completing the regional level analysis and provided an additional source of data for the detailed field studies. This system is maintained by the Bartlesville Project Office (BPO) of the Department of Energy, which also provided computer time for the TORIS regional analysis. Special thanks goes to Mr. R. Michael Ray, the deputy director of BPO, for his technical assistance and critical advice in completing the project.

BEG characterized major oil and gas reservoirs in Texas, New Mexico, and Oklahoma into distinct and separate plays based upon an extensive literature review of depositional systems, trapping mechanisms, structural setting and other geologic information. They assigned heterogeneity factors to each reservoir in the plays, thereby providing a geologic basis for estimating the recovery potential of oil and associated gas recovery for the three-state region. Reservoir data used in the recovery-potential estimates were reviewed and complemented by the BEG staff. BEG also constructed several closely spaced permeability cross sections in the Dune and West Ranch (41-A) reservoirs. BEG and ICF Resources utilized these cross sections to develop pay-continuity functions that were later used in the determination of the volumes of recoverable mobile oil in each of these Texas reservoirs and their associated plays.

Mr. H. William Hochheiser of the Office of Geoscience Research served as the technical project officer for the detailed reservoir evaluations. His timely reviews, input, and technical guidance were essential to the completion of these analyses. Mr. Thomas Wesson, director of BPO, is the technical project officer of the TORIS contract and also provided important suggestions, reviews, and encouragement during the project.

The studies were completed under DOE contracts DE-AC01-85FE60603 and DE-AC19-86BC14000. While acknowledging the assistance of all contributors, errors in fact, analysis, or interpretation are the responsibility of the principal contractor's director and the individual project managers.

Major Reports of the Analytic Series:

- Volume 1 - Production Potential of Unrecovered Mobile Oil Through Infield Development: Integrated Geologic and Engineering Studies - Overview

- Volume 2 - An Assessment of the Reserve Growth Potential of the San Andres/Grayburg Carbonate (South Central Basin Platform) Play in Texas

- Volume 3 - An Assessment of the Reserve Growth Potential of the Frio Barrier-Strandplain Play in Texas

- Volume 4 - An Assessment of the Reserve Growth Potential of the Clear Fork Platform Carbonate Play in Texas

- Volume 5 - Producing Unrecovered Mobile Oil: Evaluation of the Potential Economically Recoverable Reserves in Texas, Oklahoma, and New Mexico

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EXECUTIVE SUMMARY

This report presents the results of an analysis of the potential recovery of the unswept mobile oil resource in the Clear Fork Platform Carbonate Play in West Texas. This study, part of a larger analysis of several major oil plays in Texas, was performed with the objective of improving the geologic knowledge base of Texas oil plays, increasing the understanding of reservoir heterogeneity as it relates to the geologic system of a play, and refining the conceptual and analytical tools necessary for characterizing and assessing the recovery potential of the unswept mobile oil resource in these plays. The results of this work can help better define the economic potential of the U.S. unswept mobile oil resource and assist operators in improving recovery in mature Texas oil fields.

The objective of this study is to determine the economic viability of infill drilling to recover unswept oil remaining in the Clear Fork Platform Carbonate Play. The geologic, engineering, and economic models used for assessing the potential recovery of the unswept mobile oil resource were adapted to conform with data availability and analysis time frames. The analysis was performed using "off the shelf" studies, available in the literature, and data obtained from public sources. This information was examined and utilized under a specified conceptual and analytical framework, but without independent, detailed geologic characterization and quantification of reservoir heterogeneity.

The Clear Fork Platform Carbonate Play, located in the Central Basin Platform in West Texas, produces oil and associated gas from heterogeneous interbedded carbonate and clastic reservoirs in the Leonardian Series of Permian age. The play consists of 13 major fields, each having produced over 10 million barrels (MMB) of crude oil as of 1981. The high level of heterogeneity in reservoirs within these fields leads to low recovery efficiencies, and therefore, considerable quantities of unrecovered mobile oil. All of these reservoirs have reached primary depletion, with secondary recovery programs currently underway.

The analysis demonstrates that the more intensive infill development of reservoirs in the Clear Fork Platform Carbonate Play can result in the economic recovery of significant quantities

of previously unswept mobile oil and associated natural gas. The analysis also confirms that the timing of infill development has a considerable impact on infill development economics.

Specifically, the key findings of the report are as follows:

1. Under a uniform or blanket infill development program to 10 acres per producing well, the potential recovery of unswept mobile oil in the Clear Fork Platform Carbonate Play is approximately 170 MMB of oil and 100 billion cubic feet (Bcf) of associated natural gas at oil prices less than $20 per barrel (in 1986 dollars). At a $30 per barrel oil price, an additional 40 MMB of oil and 50 Bcf of natural gas becomes economic to produce.

2. Crude oil prices and the timing of infill development govern the economics of infill drilling in the Clear Fork Platform Carbonate Play. For example, in the Robertson Clear Fork Unit, which was considered to be representative of the fields in the play, the timing of infill development on project economics is illustrated by the following:

- At oil prices of $10 per barrel, approximately 28 MMB of oil and 14 Bcf of natural gas would be economic to produce if the infill development program was initiated in an ongoing waterflood (at current conditions) at an 80-acre pattern, with economic development feasible to 20 acres per producer.
- If the infill development was not initiated until waterflood operations ceased on an 80-acre pattern, only 12 MMB of oil and 6.5 Bcf of natural gas would be economic to produce at a $10 per barrel oil price, with economic infill development feasible only to a 40-acre waterflood pattern.
- The implementation of an infill development program in a depleted field to recover only primary oil would be less economically attractive than implementation of full waterflood operations. The greater incremental recovery of the waterflood operations are sufficient to offset the increased costs associated with secondary recovery, which may not be the case in all situations.

3. The Clear Fork Platform Carbonate Play has an estimated 282 MMB of mobile oil that is contacted but most of which is bypassed by current operations. An additional 156 MMB of previously uncontacted mobile oil would be contacted, but mostly bypassed, under a blanket infill drilling program to 10 acres per producer. This bypassed oil would be primarily the target for

improved secondary recovery techniques, such as profile modification and selective zone recompletion in probable conjunction with infill development.

4. Based on the findings of previous reports in this series, geologically targeted or strategic infill drilling, compared to blanket infill drilling assessed in this report, could lead to additional recovery at lower oil prices by directing wells to the more favorable areas of the field. A thorough quantitative examination of the potential for strategic infill drilling in the Clear Fork Platform Carbonate Play could provide additional insight into methods for improving mobile oil recovery, particularly at low oil prices.

In summary, this study shows that the potential for recovering additional unswept mobile oil from the mature oil fields in the Clear Fork Platform Carbonate Play is significant. In addition, the results presented here could assist operators in the play to begin to assess the infill development potential in their own fields and improve recovery from these fields at low to moderate crude oil prices.

I. INTRODUCTION

This study reports on the continuation of play-level analyses evaluating the potential recovery of unswept mobile oil in Texas as part of ongoing research being conducted by ICF Resources and the Bureau of Economic Geology, University of Texas at Austin. The goal of this work is to establish geologic and engineering methodologies for estimating the potential of the unswept mobile oil resource and to identify, analyze, and determine the impact of cost effective methods to convert this important resource into domestic reserves.

The refinement of geologic and engineering methodologies utilized in determining the economic potential of the unrecovered mobile oil resource is being developed through the assessment of major Texas oil plays. The research is focused on improving the geologic knowledge base of Texas oil plays, increasing the understanding of reservoir heterogeneity as it relates to the geologic systems of the hydrocarbon plays in the state, and on defining and improving the tools (analytical and conceptual) necessary for characterizing and assessing the recovery potential of the resource. The knowledge gained as a result of this effort can be transferred to Texas oil field operators and used to increase production, hence helping to delay the production decline and well abandonments in mature Texas oil fields.

This effort is based on the concept that increased knowledge concerning the origin of hydrocarbon reservoirs, including the depositional, diagenetic, and tectonic history, can be used to better predict the location, characteristics, and conditions under which the remaining unswept mobile oil resource exists in Texas oil fields. Potential recovery, production response, and economic viability are assessed based on specific geologic conditions and engineering requirements related to various fields in this play.

The study of the Clear Fork Platform Carbonate Play is intended to refine the geologic, engineering, and economic models used to evaluate the unswept mobile oil resource. Methods for the characterization of the resource and assessment of its recovery potential which are adaptable to varying data availability and analysis time frames are discussed. This analysis builds on previous analyses of two major Texas hydrocarbon plays -- the San Andres/Grayburg (South Central Basin Platform) and Frio Barrier-Strandplain Plays. However, unlike the analyses performed on these two plays, in which detailed geologic and engineering analyses were used to define and quantify reservoir heterogeneity, characterize the resource, and assess its recovery potential, this study is based on geologic and engineering data obtained from "off the shelf" studies and data available in the literature. The existing literature is examined under the conceptual and analytic framework established in the two previously assessed plays, but without the independent, detailed geologic characterization and quantification of reservoir heterogeneity performed in these previous assessments.

The successful completion of this research holds the promise for significantly increasing the understanding of unswept mobile oil and methods for assessing its recovery. The results will aid both operators with leases in the Clear Fork Platform Carbonate Play and researchers and policy makers examining ways to increase domestic crude oil production. This analysis, in addition to the two companion analyses and other related research efforts, provides a clearer definition and characterization of this often overlooked domestic energy resource.

Due to the limitations imposed by the use of only publicly available information and the absence of additional detailed technical analysis, only potential recovery from blanket infill drilling was evaluated in this study. While this method for recovering mobile oil can result in significant resource additions, its economic potential is limited by the requirement to drill a large number of wells. Previous analyses of the unrecovered mobile oil resource in other plays demonstrated the improved recovery possible with geologically targeted infill drilling. This procedure, which limits the number of wells required to effectively develop the resource, reduces the large investment requirement associated with blanket drilling. With reductions in investment and operating costs under targeted infill drilling, economic oil recovery in the Clear Fork Platform Carbonate Play could be substantially increased. The evaluation of this potential is beyond the scope of this current analysis, but remains a research objective for future work.

II. SUMMARY METHODOLOGY

The analysis of economically recoverable oil and associated gas from infill drilling of the mature oil fields in the Clear Fork Platform Carbonate Play followed a eight-step methodology, as summarized below.

Step 1. Review the Literature on the Clear Fork Platform Carbonate Play. This step involved a comprehensive search and technical review of the literature on performance, including response to infill drilling, of fields in the Clear Fork Platform Carbonate Play. In addition, all publicly available data on reservoir characteristics for major fields in the play were collected.

Step 2. Determine the Representative Field or Unit in the Play. Based on the thorough review of the literature, a representative field or unit in the play was selected. The unit selected was the Robertson Clear Fork Unit in the Robertson North Field in Gaines County, Texas.

Step 3. Quantify the Unswept Mobile Oil Resource and Reservoir Heterogeneity within the Selected Unit. Continuity curves and other information in the literature were used to quantify the remaining mobile oil resource in the unit. Additional analysis of information obtained from the literature enabled the estimation of reservoir-wide heterogeneity and the productivity of infill wells in the Robertson Clear Fork Unit.

Step 4. Trace the Development History of the Robertson Clear Fork Unit. The development history of the Robertson Clear Fork Unit was used to verify the estimated reservoir continuity as a function of well spacing and to establish the recovery potential of the field.

Step 5. Determine Technically Recoverable Oil and Associated Gas. The additional crude oil and associated natural gas recoverable from extended blanket infill drilling of the Robertson Clear Fork Unit was estimated using the continuity relationships and reservoir data collected from the literature.

Step 6. Establish Economically Recoverable Oil and Associated Gas. Economic and financial analyses were used to establish the costs and feasibility of oil recovery from blanket infill drilling in the Robertson Clear Fork Unit.

Step 7. Establish "Target" Oil and Gas for the Individual Fields in the Play. Volumetric reservoir data and historical drilling and production data were used to estimate the uncontacted mobile oil remaining in each major field in the Clear Fork Platform Carbonate Play, thus establishing the uncontacted mobile oil in each field, the target for infill drilling.

Step 8. Use the Results for the Robertson Clear Fork Unit to Estimate Recovery for the Other Fields in the Play. The results for the representative unit were extrapolated to determine the recovery potential of all the major fields in the Clear Fork Platform Carbonate Play. Specific data on each individual field were combined with the pay continuity relationship and recovery potential established for the Robertson Clear Fork Unit to estimate the recovery potential for each field. These field-by-field results were aggregated to determine the overall cost/supply curve for the play.

Detailed explanations for each step of the study methodology, including the data used and the models employed, is contained in appropriate sections of the report.

III. GEOLOGY OF THE CLEAR FORK PLATFORM CARBONATE PLAY

The Clear Fork Platform Carbonate Play, located on the Central Basin Platform in West Texas, produces oil from heterogeneous interbedded carbonate and clastic reservoirs in the Leonardian Series of Permian age. Thirteen main reservoirs in the Clear Fork Platform Carbonate Play have each produced more than 10 million barrels (MMB) of oil to 1981 (Figure 1). Most of the reservoirs in the play were discovered in the 1940s, although the Sand Hills (Tubb) Reservoir, which established the productive potential of the play, was discovered in 1930. All of these fields have reached primary depletion, and secondary-recovery programs are well underway in each reservoir.

Low recovery efficiencies in Clear Fork Platform Carbonate fields are the result of numerous, laterally discontinuous pay zones and wide variation in porosity and permeability over short distances. Considerable quantities of unrecovered mobile oil still exist in these fields after primary production. Large volumes of unswept mobile oil also remain after waterflooding, thereby justifying a program of infill drilling to contact and economically produce oil previously trapped in isolated reservoir compartments.

A. DEPOSITIONAL SETTING

1. Lower Clear Fork and Tubb - Leonardian sediments, which include the Wichita and Clear Fork Groups, (Figure 2), were deposited on the semi-restricted Central Basin Platform in shallow, moderate- to high-energy environments, allowing accumulation of abundant carbonate sediments (Galloway and others, 1983). The Lower Clear Fork Formation in the region of the Robertson Clear Fork Unit was deposited in a marine-dominated, subtidal setting and contains a variety of shallow-marine fossils (Barbe and Schnoebelen, 1987). Lenticular, high-energy oolite and pellet bars accumulated on the shallow shelf (Mazzullo, 1982). In the Robertson Clear Fork Unit, however, the dominant high-energy shelf facies observed in whole core are thin (0.5 feet to 2 feet; 0.15 to 0.6 meters) mollusk packstones and grainstones that are encased in lower permeability fusilinid-echinoderm wackestones. Minor occurrences of organic buildups defined by sponge and algal structures in 1 to 2 feet (0.3 to 0.6 meters) intervals are also present.

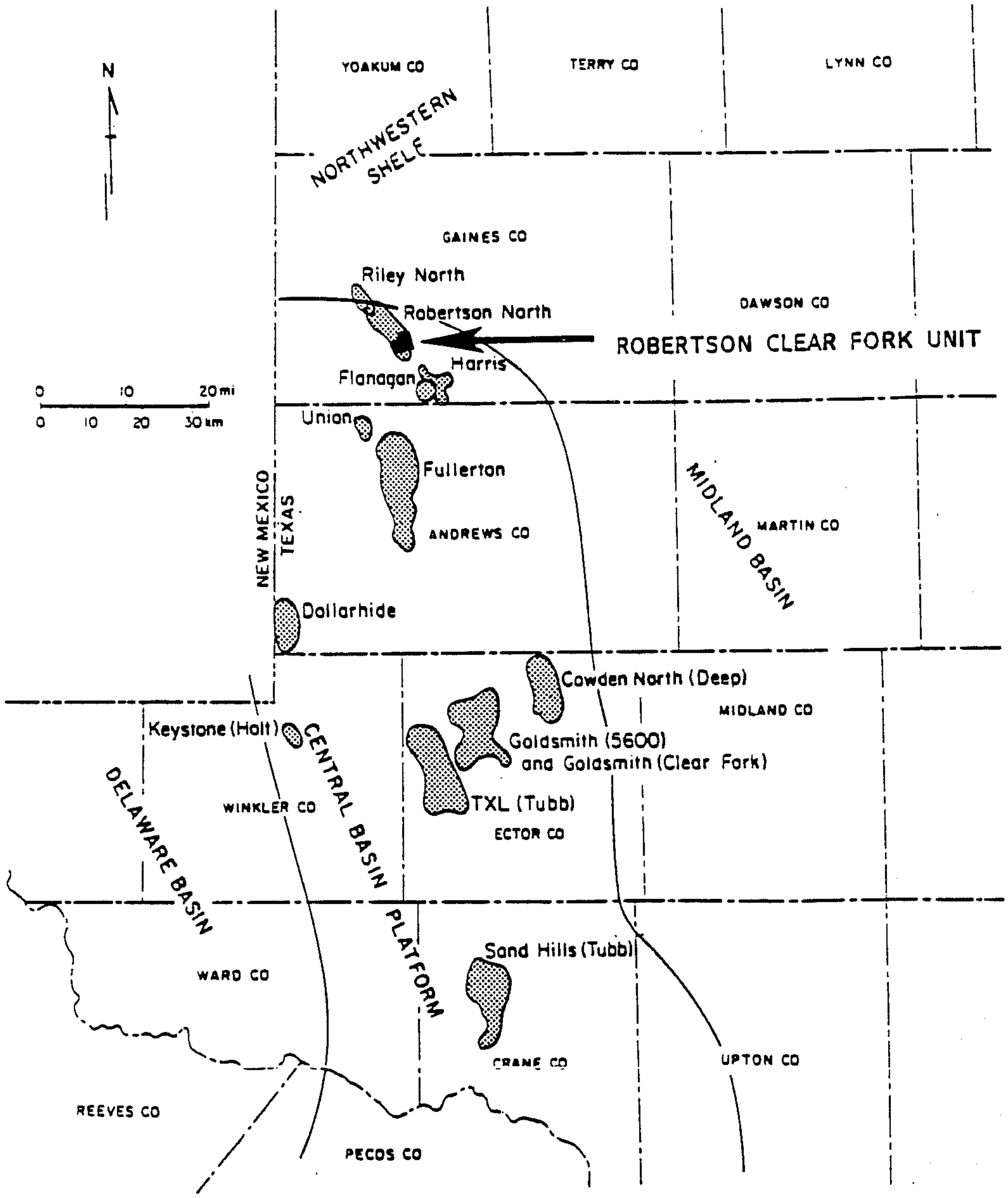


Figure 1. Location of Robertson Clear Fork Unit in the Clear Fork Platform Play. The 13 fields in this play have each produced more than 10 MMbbl of oil to 1981. Modified from Galloway and others (1983) and Barbe and Schnoebelen (1987).

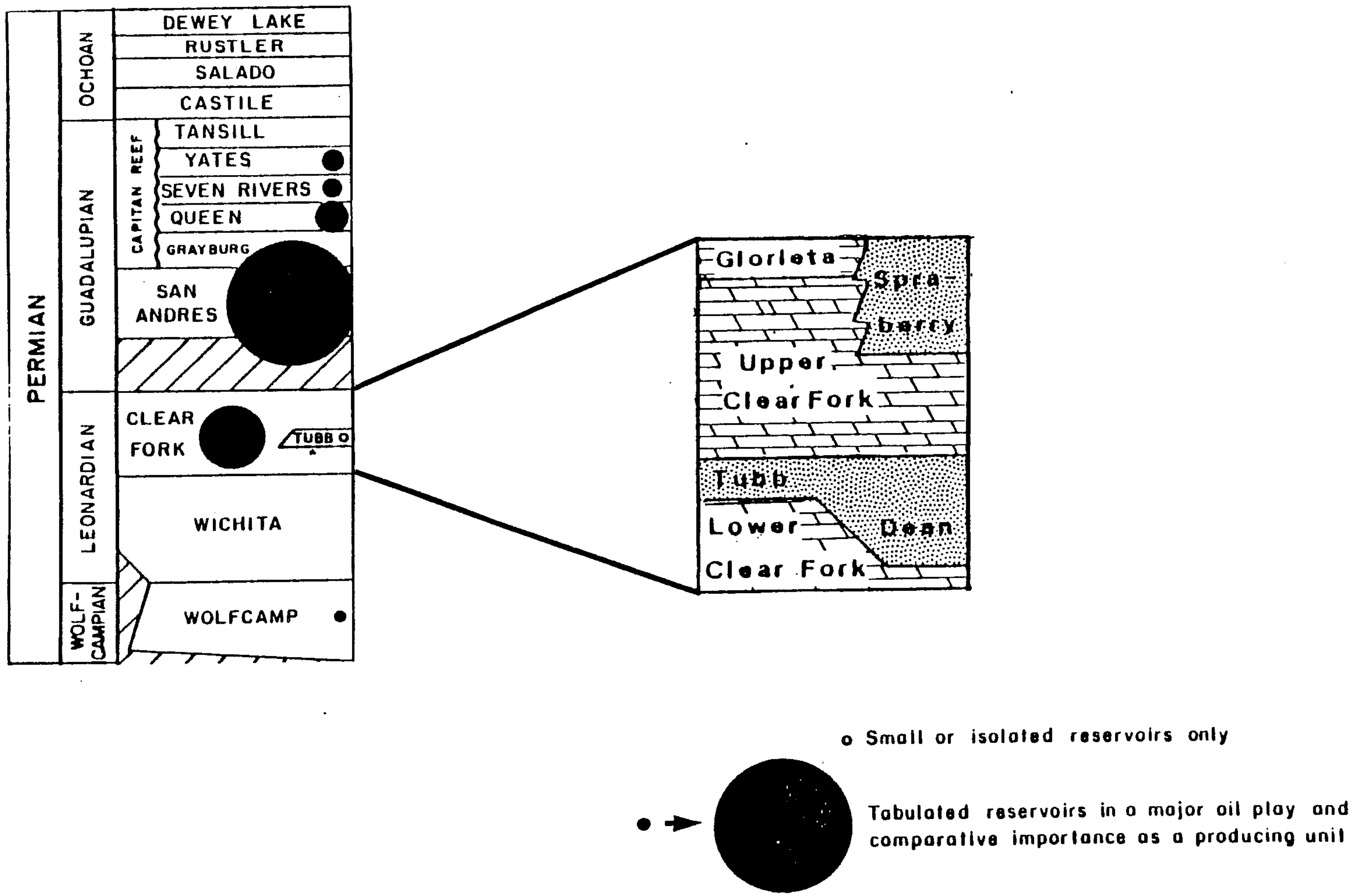


Figure 2. Mixed carbonate-clastic stratigraphy of the Leonardian (Permian) Lower Clear Fork, Tubb, Upper Clear Fork and Glorieta Formations in the Midland Basin, West Texas. The majority of reservoirs in the Clear Fork Platform Carbonate Play are found in dolomitized strata of the Lower Clear Fork, Upper Clear Fork and Glorieta. Clastics of the Tubb Formation are also productive in other reservoirs in the play. Modified from Mazzullo (1982) and Galloway and others (1983).

Lower Clear Fork subtidal and intertidal facies are bounded updip by sabkha, wadi, and eolian facies from arid coastal environments (Figure 3; Handford, 1981). Downdip, inner-shelf lagoon and shoal facies of the Lower Clear Fork grade into low-energy outer shelf and slope facies (Figure 4; Mazzullo, 1982). At the end of Lower Clear Fork deposition, clastics of the Tubb Formation were introduced into the basin, resulting in a change to a mixed siliciclastic and carbonate rimmed shelf system similar to the modern southeastern coast of North America (Ginsburg and James, 1974). Fluctuations in relative sea level resulted in cyclic deposition and rapid shelf outbuilding, typical of other Permian reservoirs in West Texas. Meteoric waters mixed with pore fluids in the carbonates, causing leaching and dissolution of grains, as well as selective dolomitization and modification of porosity (Galloway and others, 1983).

2. Upper Clear Fork and Glorieta - As the shelf on the northeastern margin of the Central Basin Platform prograded basinward with time, sediments of the Upper Clear Fork and Glorieta Formations were deposited in increasingly regressive conditions (Barbe and Schnoebelen, 1987). The Upper Clear Fork and Glorieta in West Texas and in the Texas Panhandle contain large amounts of interbedded dolomite, sand, shale and anhydrite which were deposited in a facies tract bounded downdip by inner-shelf muddy dolomite, and updip by sabkha anhydrite and gypsum (Presley and McGinnis, 1982). The sabkha facies in turn grades updip into salt and mud flats deposited in a lower alluvial-plain setting (Figure 5).

Interfingering carbonate and clastic facies occur in numerous, thin transgressive-regressive cycles throughout most of the Upper Clear Fork and Glorieta. In the Flanagan (Clear Fork) Field, located about 8 miles (13 kilometers) southeast of the Robertson North Field (Figure 1), these cycles are dominated by thick sections of supratidal facies interbedded with fossiliferous marine facies, all completely dolomitized (Table 1; Lucia, 1972). The base of these cycles, which are 20 to 40 feet (6 to 12 meters) thick in the Flanagan Field, is characterized by shallow-marine facies overlain by intertidal facies. High-energy deposits are common in the marine and intertidal facies. Shallow inner-shelf pellet shoals and laterally accreting spits were deposited adjacent to tidal inlets that transported coarse-grained carbonate sediments landward and seaward. Tops of these cycles are marked by well-developed algal-flat and brine-pan supratidal facies. Eolian components are also present in the supratidal facies, and consist of ripple-laminated quartz silt.

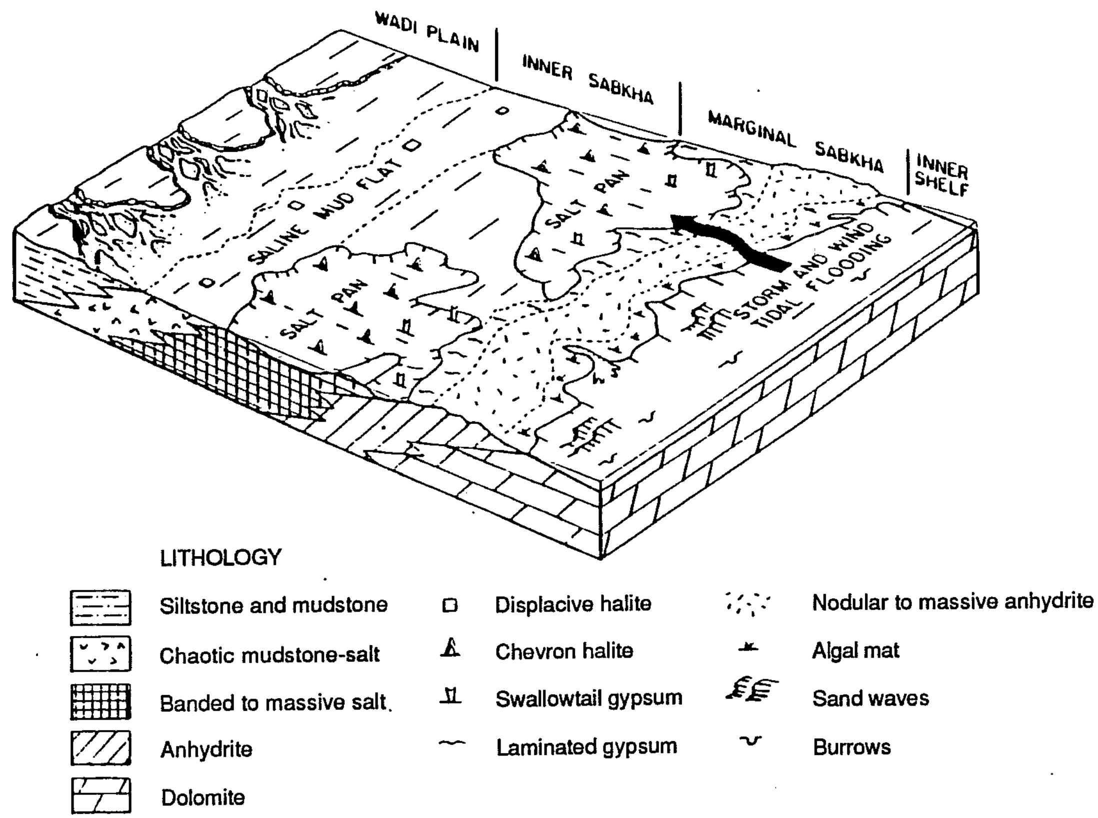


Figure 3. Near-shore and arid coastal environments from the Lower Clear Fork Formation in West Texas and in the Texas Panhandle. From Handford (1981).

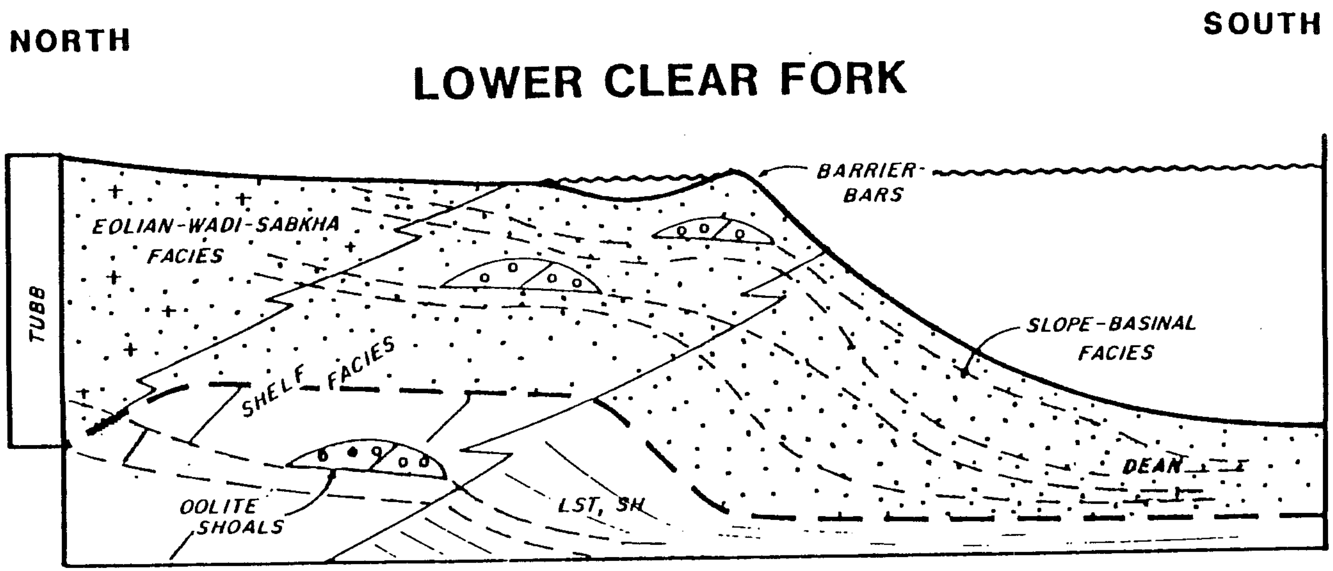


Figure 4. Idealized Lower Clear Fork facies tract, illustrating eolian-wadi-sabkha facies of the Tubb Formation interbedded with shelf facies. Basinward-thickening wedges in the Lower Clear Fork are the result of progradation of shelf-margin depositional units over slope-basinal facies of the Dean Formation. From Mazzullo (1982).

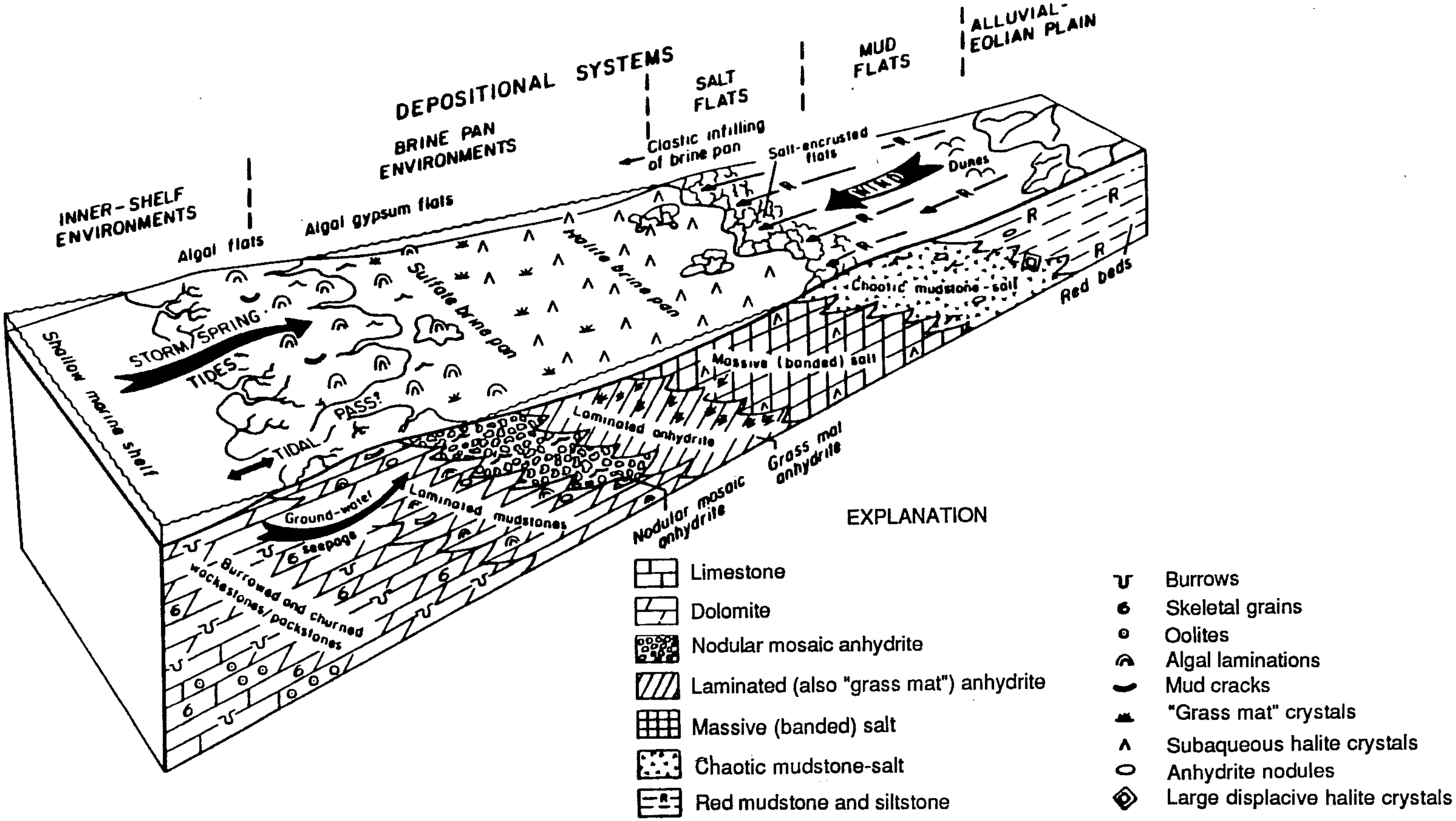


Figure 5. Idealized Upper Clear Fork and Glorieta facies tract, illustrating interbedded carbonate and evaporate depositional environments. From Presley and McGinnis (1982).

Table 1

Sedimentary Structures, Fossil Content, and Rock-Types in the Upper Clear Fork in Flanagan Field (from Lucia, 1972).

Interpreted Sedimentary Environment	Sedimentary Structure	Fossils	Particle Size
Supratidal	Irregular laminations Lithoclasts Dessication features Quartz silt beds	*Rare* Thin-shelled small forams, ostracods, molluscans.	Lithoclasts to lime mud.
Intertidal	Distinct burrows Churned-to wispy-mottled structures Algal stromatolites Discontinuous fractures	*Very few* Thin-shelled small forams, ostracods, molluscans. Filamentous algae.	Fine sand-size pellets to lime mud.
(channel)	Current-laminated rocks Cross-bedding	*Very few* Echinoids. Small molluscans.	Fine sand-size pellets to mud with lithoclasts.
Marine	Churned rocks Burrowed rocks	*Locally abundant* Echinoids, bryozoans, large fusulinids, molluscans, algal-forams (?)	Coarse sand-size pellets to lime mud.

Upper Clear Fork and Glorieta facies types and distribution are similar to those presently occurring in the Persian Gulf, which is a restricted embayment located between Iran and Saudi Arabia. Carbonates, evaporites, and wind-derived clastics are accumulating on the low-relief western margin of the Gulf (Wagner and van der Togt, 1973). Some areas on the western margin of the Persian Gulf, particularly in the Qatar Peninsula, are sites of active coastal accretion and offlap. The distribution of carbonate and clastic facies is highly complex, due to the interaction of longshore transport, tidal currents, and wind patterns (Shinn, 1973a).

Pellet and skeletal carbonate grains in the subtidal environment offshore of the Qatar Peninsula are reworked by longshore currents into shore-parallel cheniers and recurved spits. Other carbonate-grain accumulations in the subtidal environment occur as discontinuous shoals seaward of the chenier ridges or as winnowed lags in tidal channels. As the shoreline progrades, these deposits are overlain by intertidal and supratidal sediments. A vertical sequence through an offlapping sabkha complex in the Persian Gulf (Shinn, 1973b) shows burrowed, fossiliferous subtidal facies overlain by laminated evaporites and crossbedded silty sands deposited by dunes migrating over the surface of brine ponds and tidal flats. Although the entire sequence is about 80 feet (25 meters) thick, much of the eolian section will be removed during the next period of transgression, resulting in a thinner preserved cycle comparable in thickness to that observed in the Clear Fork section.

B. DRIVE MECHANISMS AND RECOVERY EFFICIENCIES IN THE PLAY

Solution-gas drive is the dominant oil recovery drive mechanism in the Clear Fork Platform Carbonate Play. Reservoir pressure in these fields declined rapidly, which is typical in solution-gas drive reservoirs. Secondary recovery efforts were eventually implemented in order to recover more of the original oil-in-place. Gas injection was initiated in the Fullerton Field in 1954 and was followed by a successful waterflood in 1956. Although similar secondary-recovery techniques have also been adapted to other fields in the play, the overall recovery efficiency remains exceptionally low, averaging only 23 percent (Galloway and others, 1983). This low recovery is a function of the high degree of reservoir heterogeneity and long, sustained periods of primary production. Infill-drilling programs at 20-acre spacing in some fields have already been authorized by the Texas Railroad Commission. The effectiveness of even closer well spacing (10-acre) has been demonstrated by Stiles (1976) and Barber and others (1983) in the Fullerton Field, and by Barbe and Schnoebelen (1987) in the Robertson North Field.

C. DOMINANT TRAPPING MECHANISMS IN THE PLAY

Most traps in the Clear Fork Platform Carbonate Play are structural, consisting of asymmetric, faulted anticlines. However, the productive area in many Clear Fork fields is modified by porosity and permeability pinchouts related to irregular distribution of reservoir facies, as illustrated on a structure map of the Sand Hills (Tubb) Reservoir (Figure 6; Galloway and others, 1983). Stratigraphic traps in Clear Fork reservoirs are related to both lateral and vertical changes in porosity and permeability, such as in areas where porous shelf dolomites pinch out updip into non-porous sabkha anhydrite, or where dolomites are overlain by sabkha facies deposited during periods of coastal offlap. Diagenetic trapping mechanisms, which imperfectly correspond to facies boundaries in Clear Fork fields, are important but subtle features that modify the primary porosity distribution. Areas in Clear Fork reservoirs where porosity has been modified by filling of pores by anhydrite and other late-stage diagenesis are difficult to predict, but appear to be most clearly related to leaching by meteoric waters during periods of lower sea level (Galloway and others, 1983).

D. MAJOR RESERVOIR FACIES IN THE PLAY

Clear Fork reservoir facies are diverse and reflect mixed clastic and carbonate deposition that took place on the Central Basin Platform during Leonardian time. Individual Clear Fork reservoir units, composed mostly of dolomite and silty sandstones, are thin, laterally discontinuous, and interbedded with impermeable strata. Multiple reservoir units are common in Clear Fork fields, where the productive intervals may include as many as 70 individual pay stringers, each only 1 to 3 feet (0.3 to 1 meter) thick.

As a result of mixed clastic and carbonate deposition in the Clear Fork Platform Carbonate Play, porosity distribution is extremely irregular. Commercial production from Clear Fork fields occurs only where porosity is abnormally high (Neel, 1957). The most common porosity types in

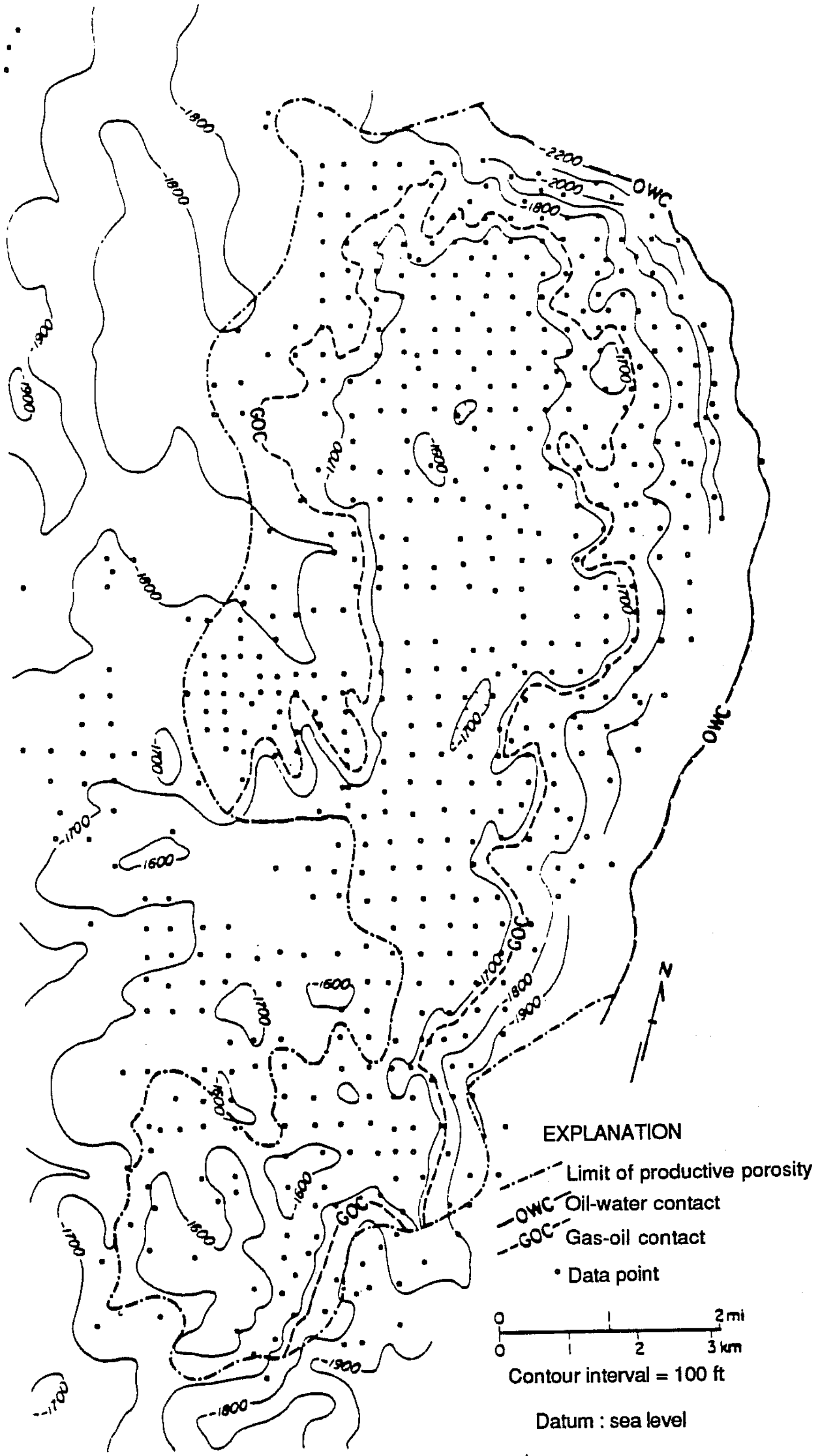


Figure 6. Structure map contoured on the top of the Tubb Formation in Sand Hills field, located on Figure 1. The productive limit does not conform to field structure, and is the result of irregular distribution of heterogeneous carbonate, evaporite and clastic facies similar to those observed in the modern Persian Gulf. Modified from Galloway and others (1983).

these fields are moldic and intergrandular, although some vugular porosity is also present. Average porosity in the play is 12 percent, and permeability averages 15 md (Galloway and others, 1983).

The bulk of Clear Fork reservoir facies occurs in strongly dolomitized carbonate strata. Jeary (1978) proposed the existence of prograding barrier reefs along the Clear Fork shelf edge, but later work by Mazzullo (1982) suggests that Clear Fork shelf-marginal dolomitized reservoirs occur as offlapping oolite shoals, separated by shales and impermeable carbonate beds. Oolitic deposits in the base of tidal-inlets have also been observed, but are of secondary importance as carbonate reservoir facies because porosity in this facies is commonly occluded by pore-filling anhydrite.

Coastal-plain clastic reservoir facies in the Clear Fork Platform Carbonate Play include eolian and wadi sandstones interbedded with sabkha anhydrites and lagoonal silty dolomites. Shore-zone clastic reservoir facies such as strandplain and tidal delta may also be present, based on a comparison of the Clear Fork to the western margin of the Persian Gulf (Shinn, 1973b). These clastic facies are most commonly observed in the Tubb, Upper Clear Fork, and Glorieta Formations. However, the Tubb Formation is less sandy in the region of the Robertson Clear Fork Unit, where it is characterized by silty and sandy dolomite instead of sandstone (Neel, 1957). Shelf siltstones and sandstones in the Clear Fork have also been documented by Silver and Todd (1969), but little is known about their reservoir potential.

E. RESERVOIR DIAGENESIS

Diagenesis significantly altered original porosity distribution in Clear Fork sediments. Diagenesis in Clear Fork fields was similar to that in other Permian fields in West Texas such as the Dune Field (Bebout and others, 1987). As in San Andres/Grayburg reservoirs, the major diagenetic event in Clear Fork reservoirs was pervasive dolomitization resulting in the formation of moldic porosity and the reduction of original porosity in virtually all facies. However, the original depositional environment was a controlling factor in preservation of some intergranular porosity, which is most common in the inner-shelf pellet and skeletal grainstones. Minor occurrences of secondary vugular porosity in the Clear Fork was caused by late-stage dissolution of dolomite and anhydrite cement.

IV. GEOLOGY OF THE ROBERTSON CLEAR FORK UNIT

The Robertson Clear Fork Unit was selected as the representative unit for this study because it has already undergone an intensive program of infill drilling, thereby serving as a useful model for assessing the potential for infill drilling in other fields in the play. Additionally, Barbe and Schnoebelen (1987) have provided a detailed pay-continuity analysis of the Robertson Clear Fork Unit based on pressure, production, and geologic data.

The Robertson Clear Fork Unit is located in the southern part of the Robertson North Field on the northeastern edge of the Central Basin Platform in southwestern Gaines County (Figure 1). Robertson North is one of several fields located within a trend of anticlinal structures developed on the margin of the Platform; it occupies the southeast end of a large asymmetrical anticline that also includes the Harris and Riley North Fields (Neel, 1957). Because the Robertson North Field is located further basinward than most of the other fields of the Clear Fork Platform Carbonate Play, many of the reservoir units, particularly in the Lower Clear Fork Formation, are shelf dolomites with interbedded siltstone and shale (Phipps, 1969).

A. RESERVOIR DISTRIBUTION IN THE ROBERTSON CLEAR FORK UNIT

Reservoir zones in the Robertson Clear Fork Unit are from 1,200 to 1,400 feet (370 to 430 meters) in gross thickness and occur over an interval from 5,800 to 7,200 feet (1,770 to 2,200 meters) in depth. (Figure 7). The net thickness of all pay zones occurring within the Lower Clear Fork, Upper Clear Fork, and Glorieta Formations in the Robertson Clear Fork Unit varies from 200 to 400 feet (60 to 120 meters). The Tubb Formation in the unit consists of low-porosity siltstones and shales, and is therefore unproductive. Pay zones in the unit are numerous and thin; over the entire vertical productive interval there may be 50 to 70 different pay stringers ranging in thickness from 1 foot (0.3 meters) to a few tens of feet (Barbe and Schnoebelen, 1987). These pay zones are laterally discontinuous, and pinch out from well to well (Figure 8; Barber and others, (1983).

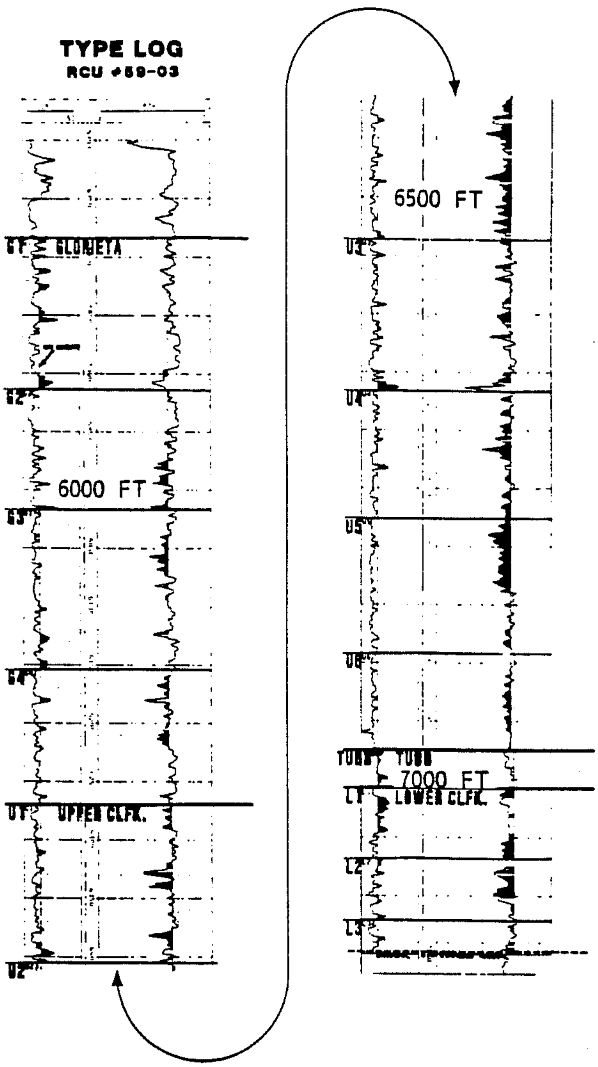


Figure 7. Type log from Robertson Clear Fork Unit in Robertson, North field, which contains 50 to 70 pay zones, each 1 ft. (0.3 m) to a few tens of feet thick in the entire productive interval from the Lower Clear Fork to Glorieta. Modified from Barbe and Schnoebelen (1987).

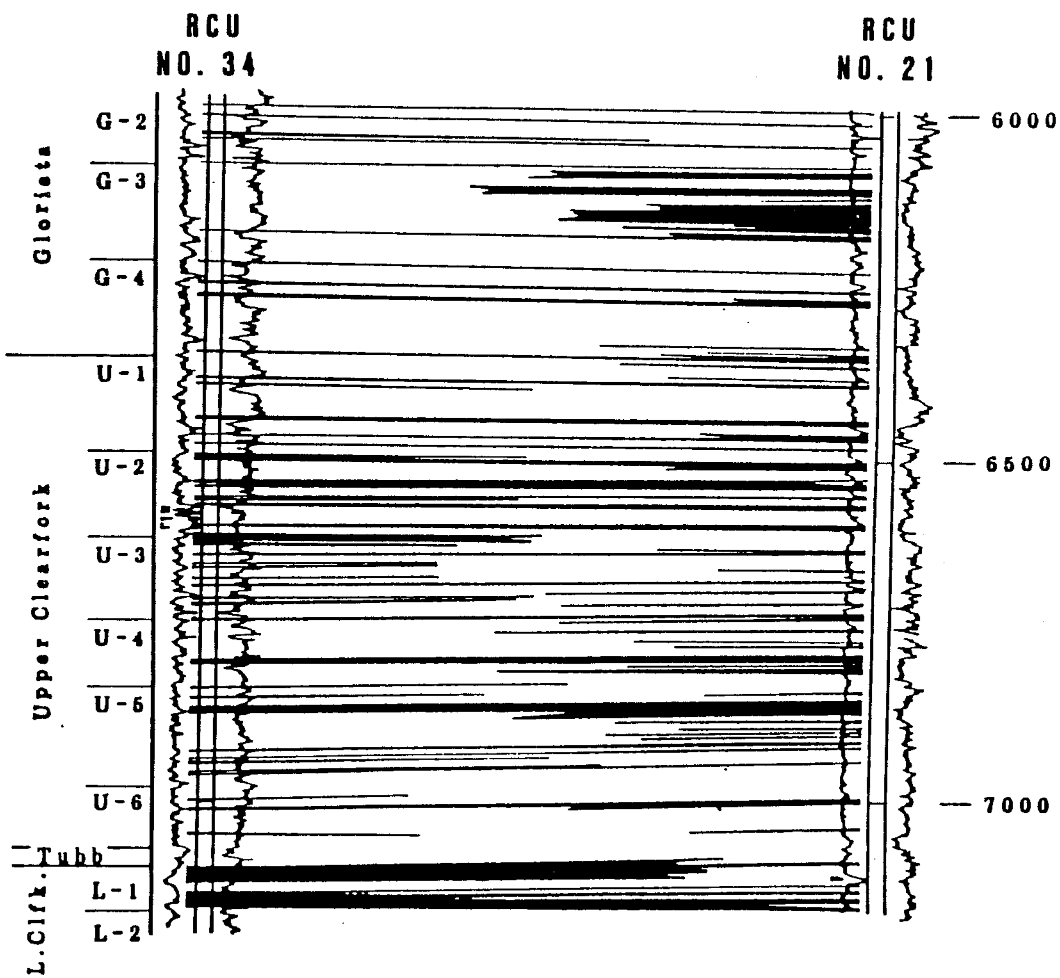


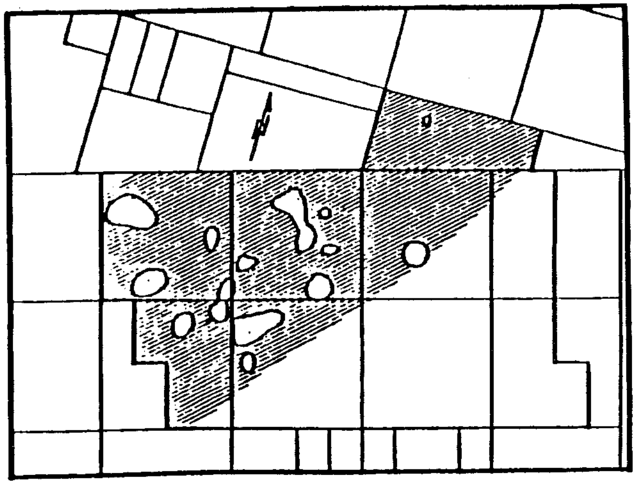
Figure 8. Reservoir heterogeneity, illustrated by discontinuity of multiple, thin, pay stringers (shown in black) at 40-acre well spacing in the Clear Fork and Glorieta in Robertson, North field. From Barber and others (1983).

Although moldic porosity contributes to the development of reservoirs in the Robertson Clear Fork Unit, the main high-quality reservoir trend for the Lower Clear Fork, Upper Clear Fork, and Glorieta coincides with the occurrence of intergranular porosity in curvilinear belts. These belts reflect the position of inner-shelf facies during deposition of each of these units and are displaced to the east (shelfward) with decreasing age, consistent with the regressive nature of the Clear Fork and Glorieta in the field (Figure 9; Barbe and Schnoebelen, 1987).

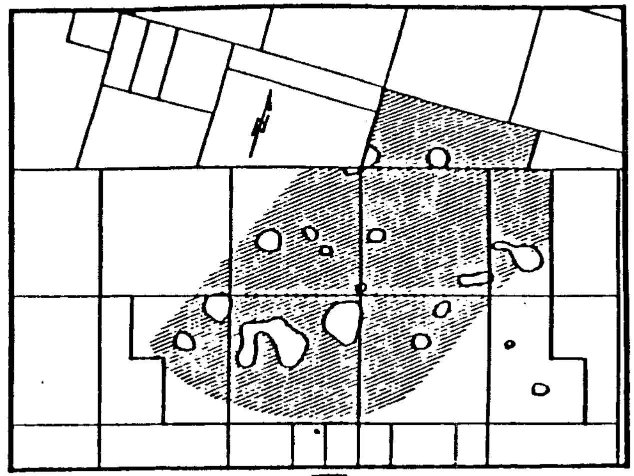
B. PAY-CONTINUITY FUNCTIONS FOR THE ROBERTSON CLEAR FORK UNIT

Barbe and Schnoebelen (1987) used three separate methods for quantifying pay-continuity in the Robertson Clear Fork Unit. These methods were based on 1) pressure analysis, 2) geologic analysis, and 3) numerical analysis. Each of the analytical methods was applied in the development of the reservoir drainable curve. The reservoir drainable curve implies that, at a certain producer-producer interwell distance, a specific portion of the reservoir volume has been contacted, and thus an estimate of drainable primary oil may be calculated. Only one of the analytical methods, the numerical analysis, was applied to the development of the reservoir drainable curve. The reservoir drainable curve is utilized in the estimate of reservoir volume in contact at a certain producer-injector interwell distance, and is used in the calculation of recoverable secondary mobile oil. The description of each of the methods used for quantifying pay continuity and comparison of the results is presented below.

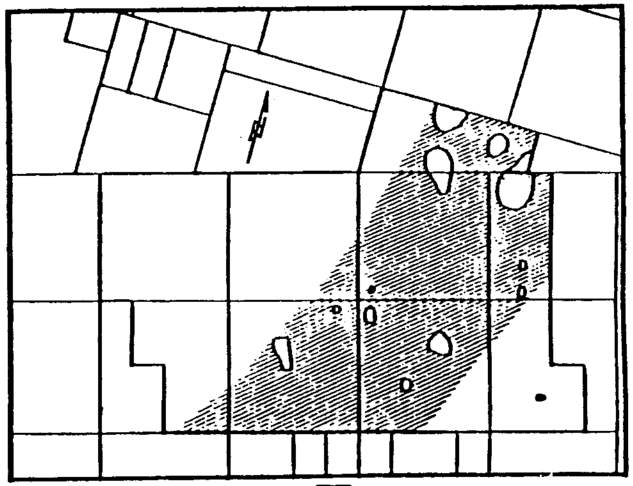
1. Pressure Analysis - The pay-continuity fraction for each injector-producer well pair in the Robertson Clear Fork Unit was calculated by analyzing their average pressures in a simple model (Figure 10). Calculated reservoir continuity in the pressure analysis method is simply the percentage of reservoir zones that are open to flow in both the injection well and producing well, and reflects the degree of pressure communication in adjacent wells. Pressure-differential data from the analysis indicate that there is about 71% pay continuity at 10-acre (660 feet) well spacing, and less than 50% continuity at 80-acre spacing (1,867 feet).



Lower Clear Fork

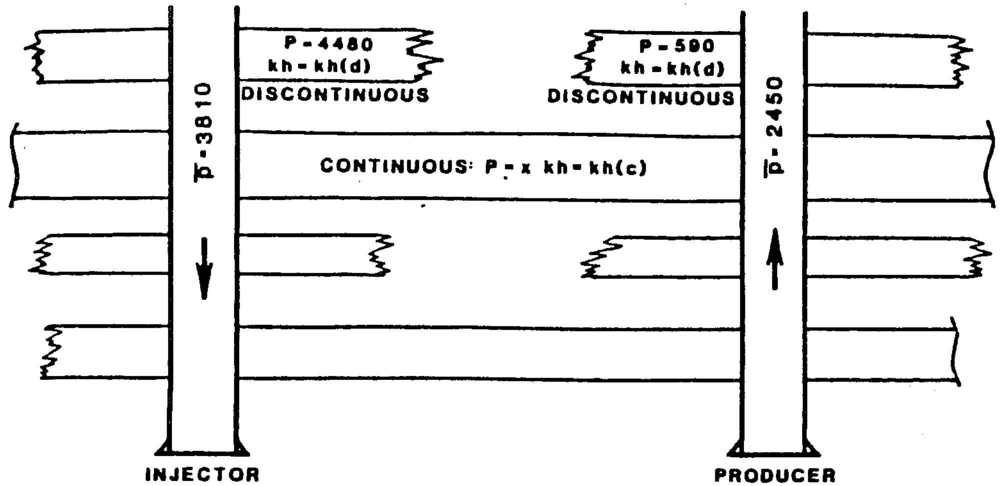


Upper Clear Fork



Glorieta

Figure 9. Basinward (east) shift of highest-quality reservoir zones with successive deposition of the Lower Clear Fork, Upper Clearfork, and Glorieta Formations in Robertson Clear Fork Unit. These areas of high-quality reservoirs correspond to the trend of inner-shelf grainstones which were deposited in three major episodes of shoreline progradation and coastal offlap corresponding to the Lower Clear Fork, Upper Clear Fork and Glorieta Formations respectively. Modified from Barbe and Schnoebelen (1987).



ASSUME: WELLBORE $\overline{p}$ = kh WEIGHTED AVERAGE

THEN FOR WIW:

$P_{wf} = 4480$

$\overline{p} = 3810$ psi

$$3810 = \frac{4480 * kh(d) - x * kh(c)}{kh(c) - kh(d)}$$

$kh(c) + kh(d) = 1$

FOR PROD.:

$P_{wf} = 590$

$\overline{p} = 2450$

$$2450 = \frac{590 * kh(d) + x * kh(c)}{kh(c) + kh(d)}$$

$kh(c) = .65$

$kh(d) = .35$

$x = 3450$ psi

Figure 10. Schematic well pair illustrating pay-continuity method based on average zonal formation pressures. From Barbe and Schnoebelen (1987).

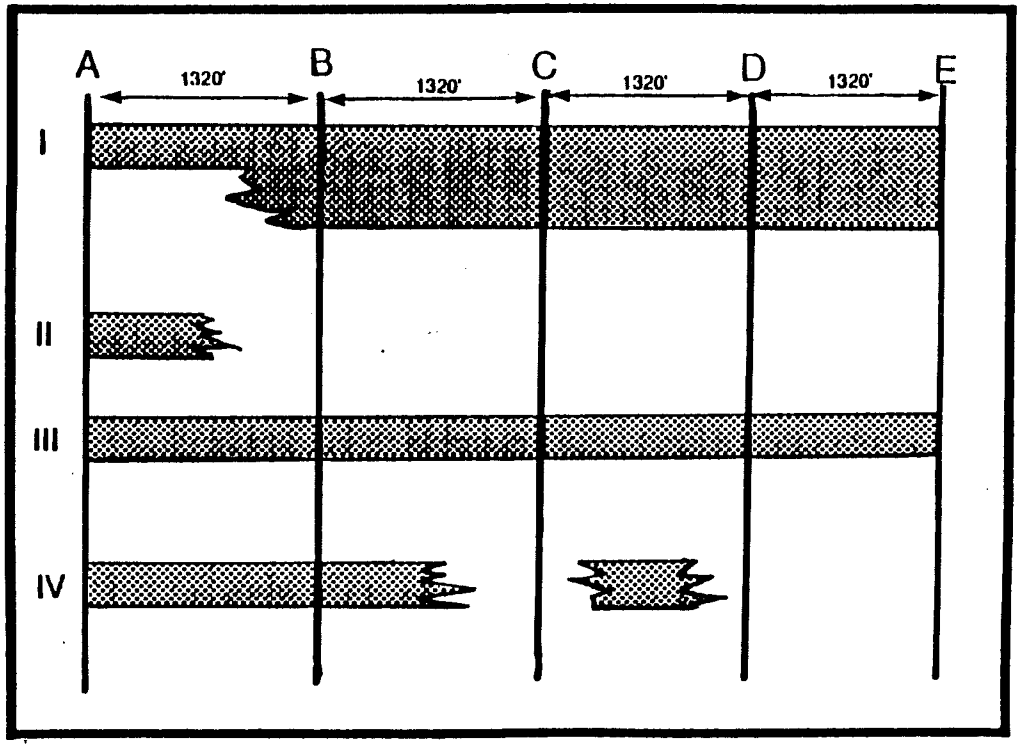
2. Geologic Analysis - The methodology used by Barbe and Schnoebelen (1987) to calculate pay continuity in the Robertson Clear Fork Unit, as it reflects geologic heterogeneity, was originally developed by Stiles (1976). The Stiles method is based on well-to-well lateral continuity of pay zones, and is expressed as the ratio of cross-sectional area of continuous pay versus total pay between well pairs (Figure 11).

3. Numeric Analysis - The numerical analysis used by Barbe and Schnoebelen (1987) for pay continuity in the Robertson Clear Fork Unit was based on produced volumes apportioned to wells at 10-, 20-, and 40-acre well spacings. Distinctions were made between drainable and floodable volumes of oil, where drainable volume describes the reservoir volume that can be drained to a wellbore by solution-gas drive, and floodable describes the reservoir volume sufficiently continuous to facilitate waterflooding between at least one injector-producer well pair.

4. Comparison of Analytical Results - As demonstrated in Figure 12, similar results were obtained from the three different methods used to establish the reservoir drainable pay-continuity curve, suggesting this curve is a reasonable estimate of pay continuity. Because of the close alignment of values from different methods, the reservoir floodable curve, established through numerical analysis only, is assumed to be a reasonable estimate of floodable continuity. Both the reservoir floodable and reservoir drainable curves show that significant heterogeneity exists in the Robertson Clear Fork Unit, and that a considerable incremental amount of oil may be contacted and produced with infill drilling. Table 2 lists the drainable and floodable continuity at 40, 20, and 10 acre spacing.

C. GEOLOGICALLY TARGETED INFILL DRILLING STRATEGIES

In this study, the potential of strategic or geologically targeted infill drilling was not assessed, as facies-specific, quantitative estimates of pay continuity were not available or could not be derived from the publicly available information used in the evaluation. However, a cursory appraisal of well performance in the Robertson Clear Fork Unit, along with a basic understanding



$$\%\ \text{Continuity} = \frac{\text{Effective Porous Volume}}{\text{Total Porous Volume}} \qquad \%\ \text{Continuity Well Pair A-B} = \frac{\text{BED I + III+ IV}}{\text{BED I + II + III + IV}}$$

Figure 11. Schematic cross section illustrating pay-continuity method based on lateral continuity of pay zones. Modified from Stiles (1976).

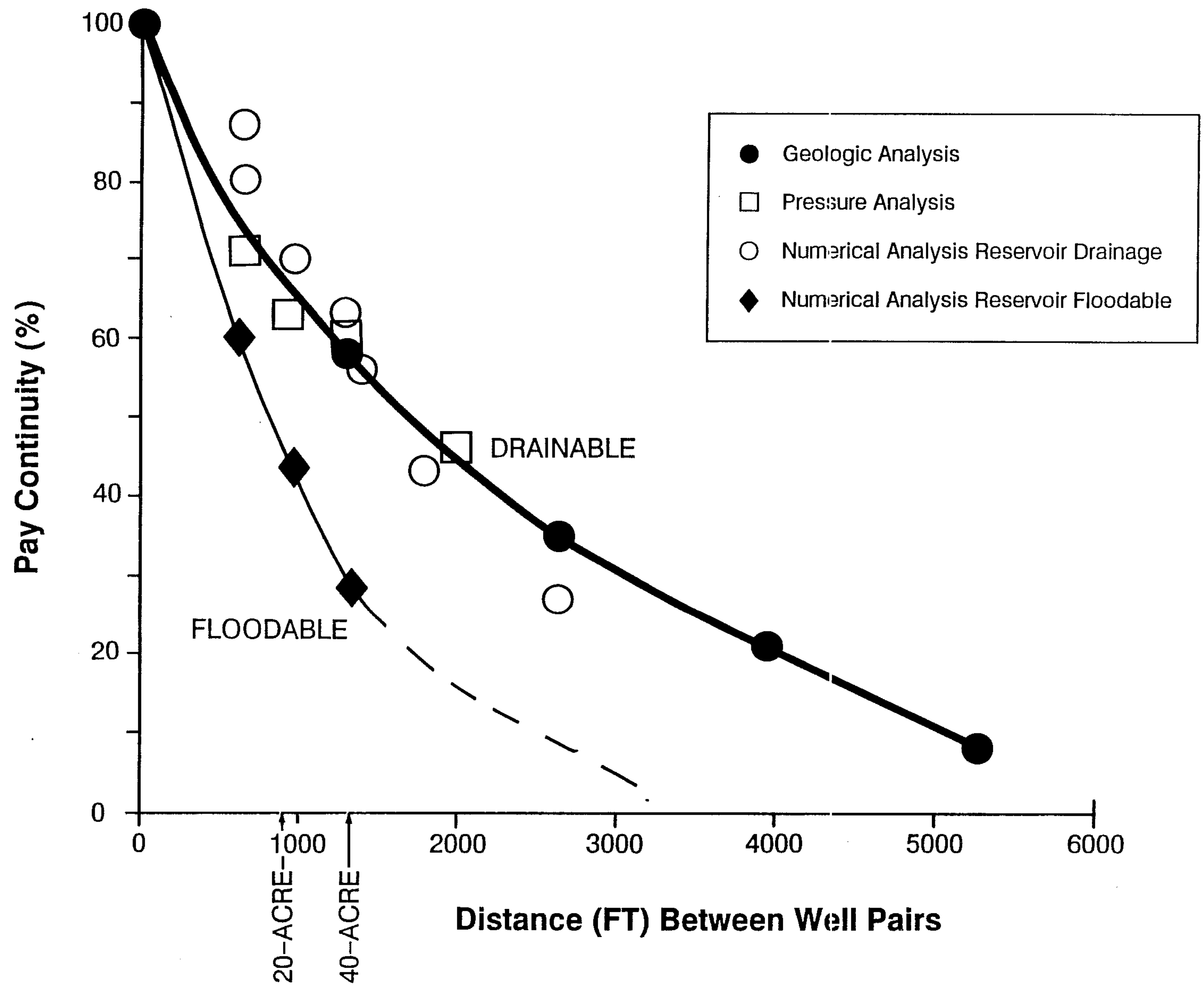


Figure 12. Reservoir (pay) continuity versus horizontal distance between well pairs in Robertson Clear Fork Unit as determined by pressure, geologic, and numeric (production) analysis. Modified from Barbe and Schnoebelen (1987).

Table 2

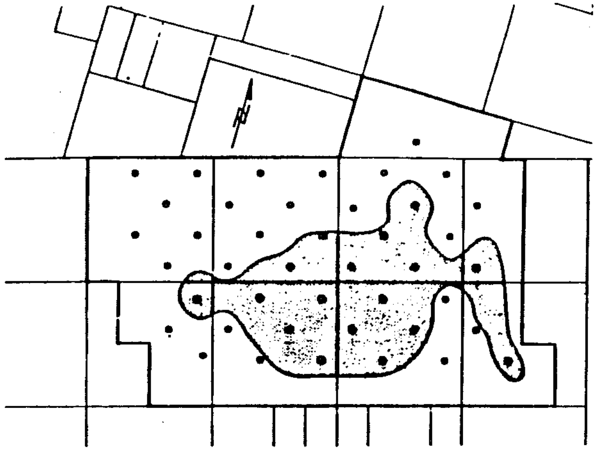
Reservoir Continuity
Robertson Clear Fork Unit

Spacing (acres/well)	Drainable by Solution-Gas Drive (Combined Analyses) (%)	Floodable (Numerical Analyses) (%)
40	58	27
20	66	43
10	73	60

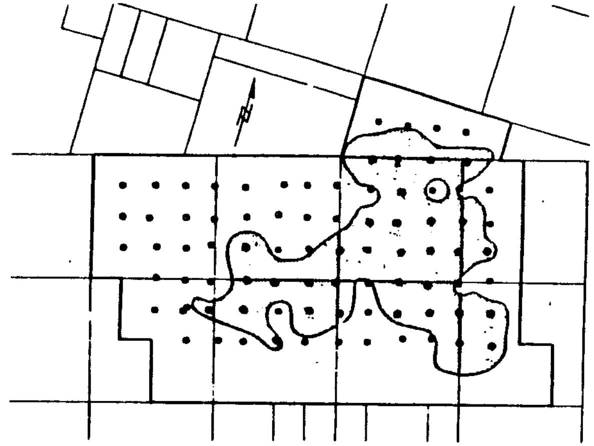
of reservoir geology and depositional systems, can provide some qualitative indication of the potential of geologically targeted infill drilling.

Excellent infill-well performance in the Robertson Clear Fork Unit indicates that the reservoir continuity at moderate to large well spacing is very low, especially in the east-central part of the unit. Areas with large numbers of infill wells coincide with areas of above-average producers at original 40-acre well spacing (Figure 13), further indicating that the greatest infill potential is found within the trend of better reservoir quality (higher porosity, higher permeability) and greater reservoir thickness (where the greatest number of reservoir zones occur). Similar results have been noted in a reservoir heterogeneity study of Dune Field in West Texas (Bebout and others, 1987).

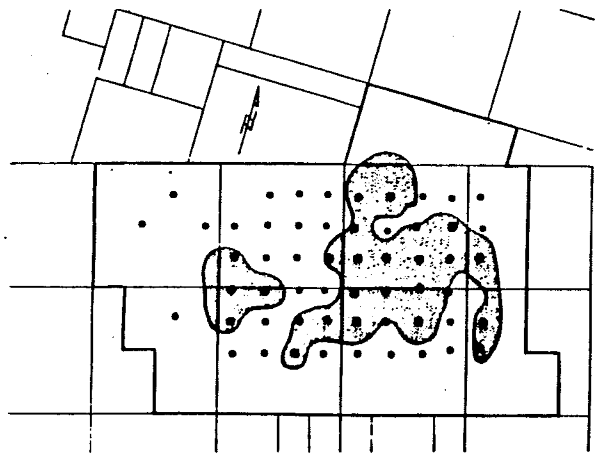
All of these production trends are reflected in the distribution of highest quality reservoirs in the Upper Clear Fork and Glorieta, which have a combined effective thickness of more than 26 porosity-feet in the east-central part of the Robertson Clear Fork Unit (Figure 9) compared with an average of 19 porosity feet unit-wide. In contrast, high quality reservoirs of the thinner



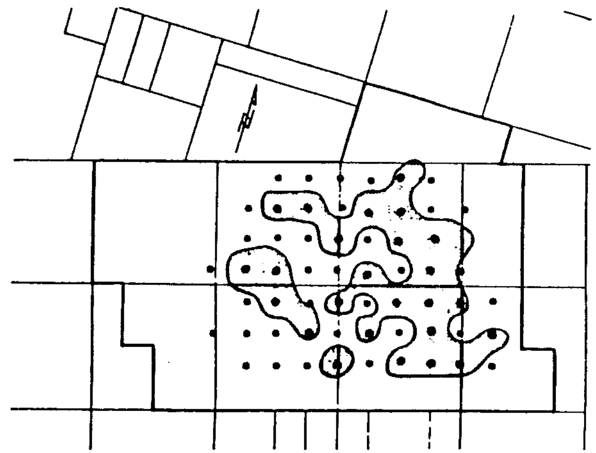
Area of above-average 40-acre producers
(estimated ultimate recovery > 450,000 bbl/well).



Area of above-average 20-acre producers
(estimated ultimate recovery > 166,000 bbl/well).



Area of above-average north/south offset producers
(estimated ultimate recovery > 92,000 bbl/ well).



Area of above-average east/west producers
(estimated ultimate recovery > 67,000 bbl/well).

Figure 13. Areas of above-average original 40-acre producers and above-average infill producers, all located in the same part of the field corresponding to high-quality inner-shelf grainstone reservoirs in the relatively thick Upper Clear Fork and Glorieta Formations. Modified from Barbe and Schnoebelen (1987).

Lower Clear Fork barely extend into the east-central area of maximum productivity and superior infill-well performance.

The areas of greatest primary production and infill-well performance correspond to strike-parallel trends containing maximum intergranular and moldic porosity, the two most common porosity types in the Robertson Clear Fork Unit (Barbe and Schnoebelen, 1987). Although moldic porosity, which is usually caused by pervasive dolomitization, may not necessarily be associated with specific facies, intergranular porosity is related to original depositional environment (Bebout and others, 1988). The strike-parallel nature of the trend of highest quality reservoirs and maximum productivity, coupled with the fact that the high quality reservoir trends show an offlapping relationship with decreasing age, suggests that the area consisting of inner-shelf carbonate-sand bars and tidal-inlet grainstone facies tract is an optimum target for infill drilling.

Although individual bars and inlet-fill grainstone units are lenticular and contain limited reservoir volumes, they occur in great numbers within thick intervals. In the Robertson Clear Fork Unit, it has been observed that 50 to 70 of these reservoir units, or "stringers," occur over the entire vertical interval of 1,200 to 1,400 feet (370 to 430 meters). In the east-central part of the unit, where the inner-shelf deposits of the Glorieta and the relatively thick Upper Clear Fork accumulated, the number of bar and inlet-fill grainstones is at a maximum, and therefore the probability of intersecting previously undrained bars with new infill wells is greater. The inner-shelf facies tract of the Lower Clear Fork is also a promising target for infill-well development, although it contains less net pay and fewer carbonate-sand bars because it is a much thinner unit than the Upper Clear Fork and Glorieta.

Geologically based infill development strategies described for the Robertson Clear Fork Unit are probably applicable to other reservoirs in the Clear Fork Platform Carbonate Play. Areas for optimum infill development in these reservoirs can be delineated by integrating production, reservoir-quality, and facies maps of major Clear Fork and Glorieta units. High-priority areas for infill development should have a major strike-parallel orientation, reflecting inner-shelf facies trends, although a few may also be developed in a dip direction within the belt of inner-shelf facies. The TXL (Tubb) and Sand Hills (Tubb) reservoirs, centrally located on the Central Basin Platform (Figure 1), also produce oil from shallow subtidal and intertidal clastic facies interbedded with productive carbonates. While prospective infill strategies for the carbonate pay zones in these reservoirs are probably similar to the Robertson Clear Fork Unit, additional evaluation by the operator may be justified to determine optimal drill sites for the clastic zones.

In summary, facies analysis is an effective method of outlining prospective areas for productive infill wells in highly heterogeneous carbonate reservoirs in the Clear Fork Platform Carbonate Play, especially when integrated with reservoir-quality and production maps. Reservoir-pressure and drainage anomalies in the Clear Fork Field and in other highly stratified, mixed carbonate and clastic fields can be systematically related to facies heterogeneities.

Facies analysis based on past infill well performance alone does not provide the information necessary for assessing the economic potential of recovering the unswept mobile oil resource in this play via geologically targeted infill drilling. The facies analysis must be combined with reservoir engineering studies and economic analysis in order to make an accurate, quantitative assessment of recovery potential. However, the review of past reservoir performance in the Robertson Clear Fork Unit shows clearly that a quantitative analysis of the potential of geologically targeted infill drilling in this unit would enhance the definition of the mobile oil resource in this region.

V. RECOVERY AND PRODUCTION ESTIMATES FOR THE ROBERTSON CLEAR FORK UNIT

The incremental recoverable oil that results from a change in well spacing consists of oil produced from both primary and secondary operations. The amount of primary oil was determined by the geologically derived, drainable continuity curve, as provided by Barbe and Schnoebelen (1987). The timing of this incremental primary recovery from individual wells was calculated using an exponential decline analysis based on historical primary production data. The volume of reservoir available to be waterflooded was determined by the "floodable" continuity curve also provided by Barbe and Schnoebelen (1987). The incremental volume of reservoir contacted in a particular development scenario was input into a waterflood production model. This model estimated the oil and water production rates and the required water injection rates necessary to sustain these production rates. The waterflood model was calibrated by a history match of actual production data from the period of time when the Robertson Clear Fork Unit was produced under an 80-acre, 5-spot pattern.

This chapter describes the methodology used to determine incremental primary and secondary oil recovery for the Robertson Clear Fork Unit. First, key reservoir parameters used in this analysis are presented. Second, the assumptions and the methodology used to determine primary production rates are examined. Third, the methodology for determining secondary oil production is presented. Finally, the history match used for calibrating the waterflood production model is discussed.

A. KEY RESERVOIR PARAMETERS USED IN THE ANALYSIS OF ROBERTSON CLEAR FORK UNIT

The values for the crucial reservoir parameters used to estimate incremental technically recoverable oil were obtained from Barbe and Schnoebelen (1987), Barber and others (1983), and Texas Railroad Commission unitization hearings records (Table 3). Analysis of the volumetric parameters shows that the Robertson Clear Fork Unit initially contained about 361 MMB of oil. Of this original resource, approximately 144 MMB were considered to be mobile oil. The oil saturation value at the start of waterflood operations was calculated using the following relation,

Table 3

Key Reservoir Data for the Robertson Clear Fork Unit

Areal Extent:	4,693 acres
Net Pay:	307 feet
Avg. Porosity:	0.063
Original Formation Volume Factor (B_{oi}):	1.38 RB/STB
Present Formation Volume Factor (B_o):	1.1 RB/STB
Oil Gravity:	35 degrees API
Oil Viscosity:	1.17 centipoise
Water Viscosity:	0.6 centipoise
Average GOR During Primary Production:	640 SCF/STB
Average GOR During Secondary Production:	490 SCF/STB
Dykstra Parsons Coefficient:	0.833
Initial Oil Saturation (S_{oi}):	0.708
Oil Saturation at Start of Waterflood (S_{oc}):	0.52
Residual Oil Saturation (S_{or}):	0.34

Sources: Texas Railroad Commission; Barbe and Schnoebelen, 1987 assuming, from the pay-continuity curve, that 58 percent of the total net pay is theoretically contacted at 40 acre spacing:

$$\text{Primary oil production} = 7758*A*h*\phi[(S_{oi}/B_{oi})-(S_{oc}/B_o)] \qquad (1)$$

where

A = productive area (acres)

h = net pay contacted at 40 acre spacing (feet)

ϕ = porosity (fraction)

S_{oi} = original oil saturation (fraction)

B_{oi} = initial formation volume factor (RB/STB)

S_{oc} = oil saturation at start of waterflood (fraction)

B_o = formation volume factor at start of waterflood (RB/STB)

Using a value of 16.2 MMB for primary oil production and the other reservoir data shown in the table, the oil saturation at start of waterflood was calculated to be 52 percent. The value for primary oil production was assumed to be the oil produced as of the end of 1970. This production was estimated by adding 839,500 barrels (one year of production at a rate of 2,300 bbls/day) to the 15,400,000 barrels reported by the Texas Railroad Commission for cumulative production as of the end of 1969. The 1970 production rate estimate was obtained from data published by Barbe and Schnoebelen (1987).

B. INCREMENTAL PRIMARY RECOVERY PREDICTIONS

The volume of primary production attributable to a change in well spacing is easily determined by multiplying Equation 1 by the percentage change in reservoir volume contacted, as established by the drainable continuity curve. Using this method, the incremental recovery by primary production was estimated, as shown in Table 4.

Table 4

Incremental Primary Production Estimated from the Continuity Function for the Robertson Clear Fork Unit

Development Scenario	Incremental Primary Production (MB)
Total at 80 acres per producer	13,343
80-40 acres per producer	3,126
40-20 acres per producer	2,266
20-10 acres per producer	1,988

The next step in the analysis was to develop a method to predict the timing of this incremental primary production. Because no actual production data from the Robertson Clear Fork Unit during the primary depletion phase of operations were available, this analysis modeled primary production for individual wells under constant exponential decline. To do so, it was necessary to determine the decline rate and the projected life for each of the four infill drilling scenarios.

The actual primary production from the Robertson Clear Fork Unit at 40 acre spacing was 16,239,500 barrels. Development of the North Robertson Clear Fork (7100) Reservoir, which is located in the unit, took place over a 20 year period. Since most of the wells were drilled in the years immediately before and after 1960, this analysis assumed that all of the wells in the unit were drilled in 1960 to 40 acre per producer spacing. This indicates that primary production from the reservoir occurred over an 11-year period. At the time waterflood operations began, the wells in the unit were producing at an average daily rate of 19.5 barrels (Bbls) per day. Knowing the cumulative primary production, final well production rate, and time required for primary depletion, the initial well rate was calculated assuming exponential decline. The initial daily production rate for an average well was estimated to be 60 Bbls/day. Given these conditions, the rate of decline for primary production under 40 acre spacing was calculated to be 10.8 percent per year.

A simplified approach was employed in order to determine the primary production decline rates at other well spacings considered in this analysis. First, the initial and final reservoir-wide production rates were calculated based on the number of producing wells required to develop the reservoir at the new spacing, assuming initial and final production rates for an average well are unchanged from those determined at 40 acre spacing. Second, the decline rate and project life associated with the production of oil originally contacted at 40 acres was determined using the new reservoir-wide production levels, assuming exponential decline. The calculated decline rate and project life were used to analyze the timing of the incremental production for each spacing considered, given the total incremental primary production determined from the continuity curve. Table 5 displays the resulting incremental primary production, project life, and decline rate for various well spacings determined using this approach.

Table 5

Incremental Primary Decline Data for the Robertson Clear Fork Unit

Development Scenario (Acres/Well)	Primary Production (Barrels)	Project Life (Years)	Decline Rate (Fraction)	Initial Unit Rate (Bbls/day)
80 - 40	3,125,628	11	0.108	1,331
40 - 20	2,265,618	6	0.215	1,843
20 - 10	1,988,195	3	0.430	3,232

C. CALIBRATION OF WATERFLOOD PREDICTIVE MODEL

Incremental secondary oil production under various infill drilling scenarios was estimated using a waterflood analysis model (Petrocalc-9, Gulf Publishing Company). The methodology used in this model is based on work published by Craig (1971), which assumes waterflood patterns that approximate a 5-spot.

The model characterizes the reservoir as consisting of 25 horizontal layers of equal thickness, each with an average porosity of 6.3 percent. Although reservoirs of this type are really segregated into layers and lenticular compartments of varying thickness and porosity, lack of sufficient data and the simplicity of the model requires the layers to be of equal thickness and porosity. The model also relies on relative permeability and fractional flow data that were not available for this study. A correlation designed for oolitic limestone lithology, which relates two-phase relative permeability to irreducible water saturation, residual oil saturation, and oil and water viscosities, was used to generate the relative permeability data necessary for running the model. This correlation is described in the Petrocalc-9 model documentation (Gulf Publishing, 1986).

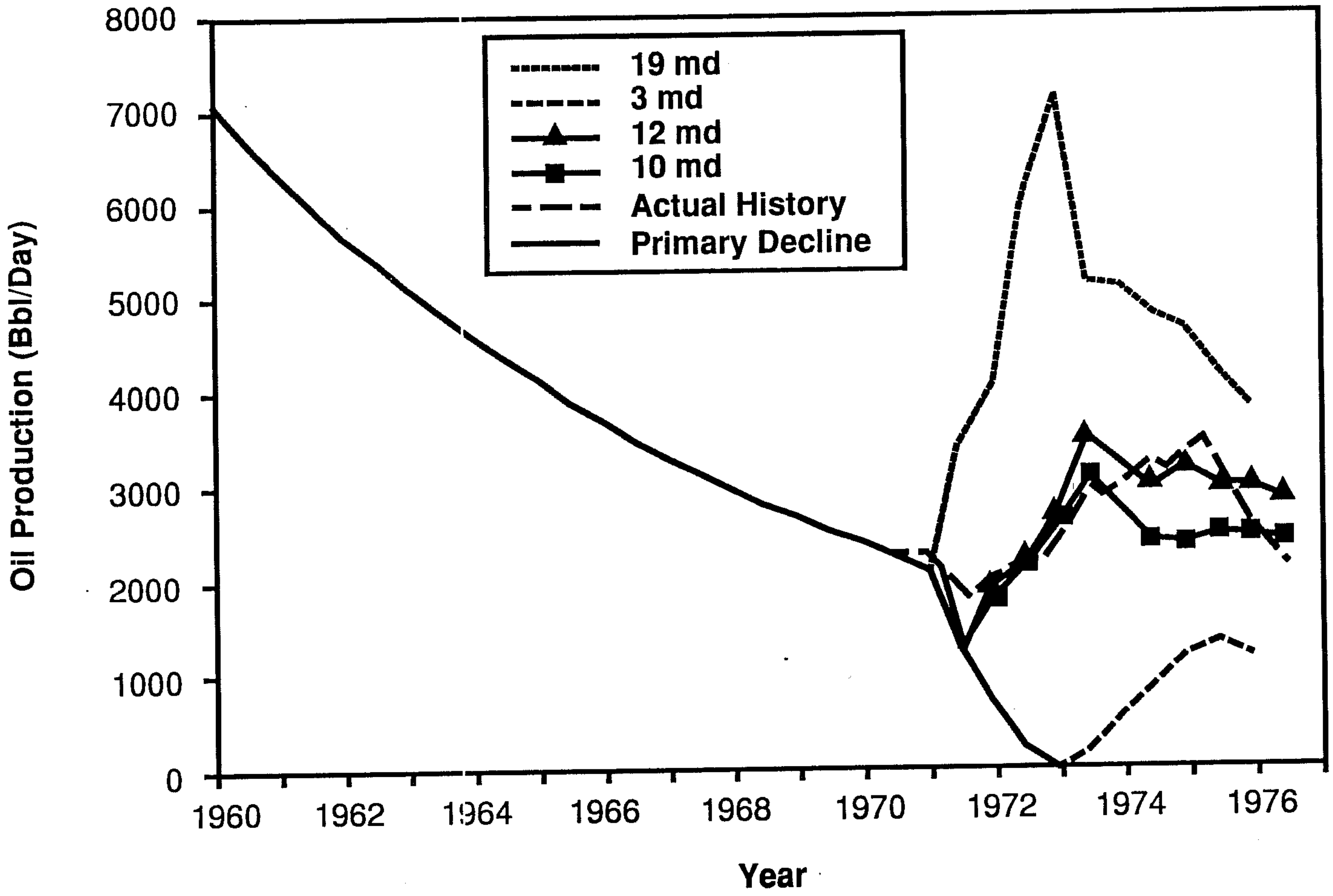
The model was calibrated by performing a history match against actual production data from the Robertson Clear Fork Unit between the years 1971 and 1976. During this time frame, full development of the Robertson Clear Fork Unit occurred, transforming a 40-acre per well primary production unit into an 80-acre per producer-injector pair, 5-spot waterflood project. Average permeability was used as the independent variable in this analysis because reported data for this parameter were inconsistent. Values reported ranged from 0.65 to 19 millidarcies. Adjustments in permeability were made in each of the 25 layers in the model to obtain the Dykstra-Parsons coefficient of 0.833 reported in Barbe and Schnoebelen (1987), while still yielding the desired average permeability value. The thickness of each layer was determined by multiplying the net pay of the unit by the floodable continuity for 40 acre producer-injector spacing, and then dividing by 25 (the number of layers).

The exact timing of the conversion from primary production methods to waterflooding is not known. This analysis assumed that all of the producer-to-injector conversions took place during a two-year period from January, 1971 to January, 1973. For the sake of the history match, the unit was divided into four equal areal sections. Waterflooding was assumed to begin in a new section every six months over the two year development period. Sections not yet converted to waterflooding during this development period were assumed to continue under primary production.

The results of the history match are shown in Figure 14. This plot shows oil production over time for the entire Robertson Clear Fork Unit. The actual production rates for the 1971-1976 time period are compared to the modeled primary production rates. The waterflood model

Figure 14

Robertson Clear Fork Unit History Match



Modified from Barbe and Schnoebelen (1987)

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results are presented for average permeability values of 3,10,12, and 19 millidarcies. The best match of production history resulted using an average permeability of 12 millidarcies.

D. INCREMENTAL RECOVERABLE OIL

The potential of infill drilling in the Robertson Clear Fork Unit was determined by analyzing the incremental costs and production associated with the following four scenarios:

- Development drilling from an 80 acre 5-spot pattern to a 40 acre 5-spot pattern
- Development drilling from a 40 acre 5-spot pattern to a 20 acre 5-spot pattern
- Development drilling from a 20 acre 5-spot pattern to a 10 acre 5-spot pattern

The calibrated model was used to determine the incremental secondary oil production resulting from the four infill drilling scenarios. Each scenario was modeled by changing the layer thickness so that the total thickness of the 25 layers was equal to the product of the average net pay of the unit and the incremental floodable continuity for the spacing scenario being analyzed. The waterflood analysis predicted that approximately 58 percent of the mobile oil in floodable contact could be technically recovered. The remainder was considered bypassed due to vertical heterogeneity and the areal sweep efficiencies inherent in a 5-spot pattern. The incremental secondary production was combined with the previously determined incremental primary production to yield the amount of recoverable oil to be input into the economics model.

The estimates for recoverable oil and gas for each of the four infill drilling scenarios are presented in Table 6. Recoverable gas is determined by assuming that oil was produced at an average gas oil ratio (GOR) of 640 standard cubic feet per stock tank barrel (SCF/STB) during primary depletion and at an average GOR of 490 SCF/STB during waterflood operations. The oil production streams estimated to be recoverable for each of the infill development scenarios are presented in Figure 15.

Table 6

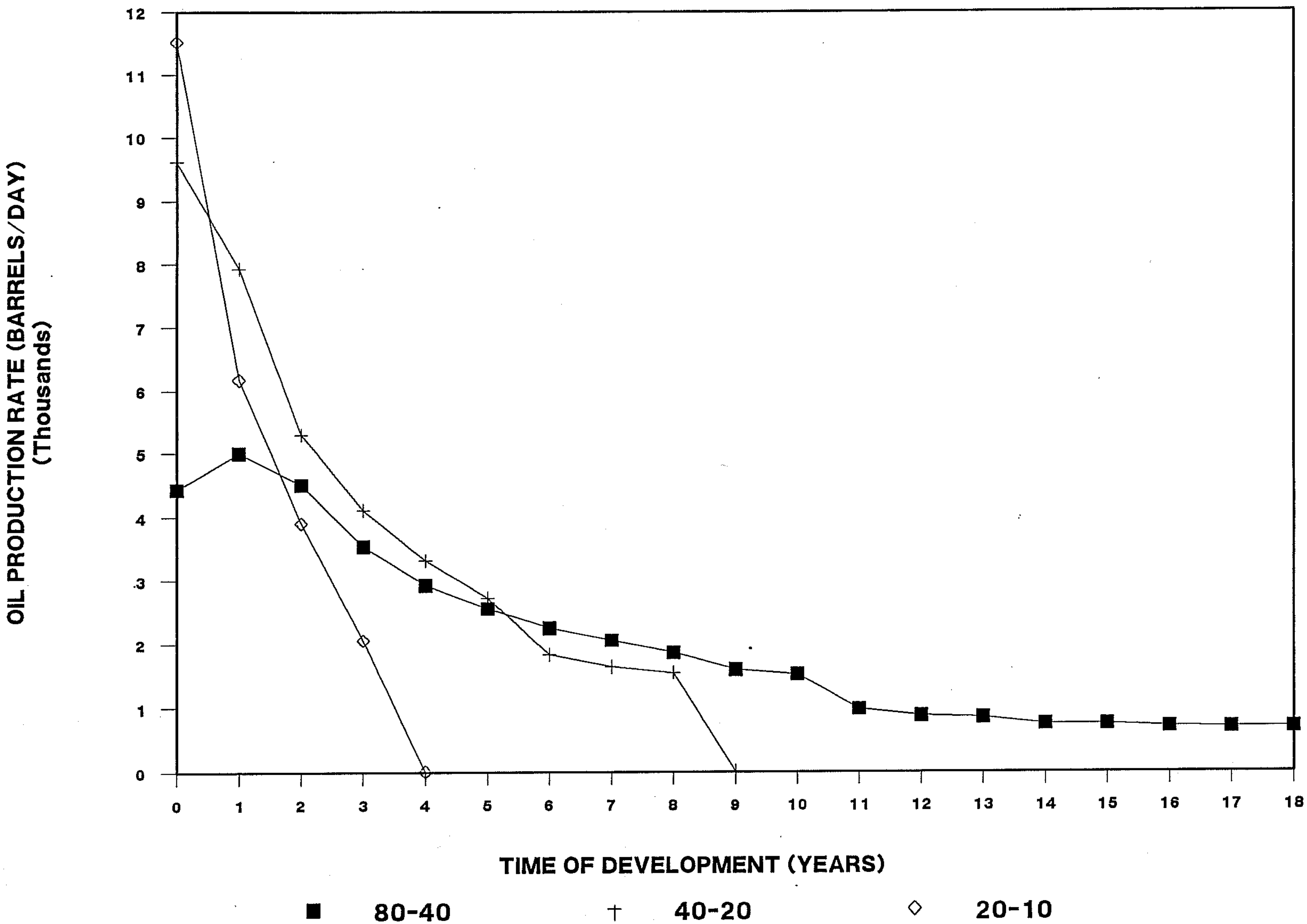
Incremental Recoverable Oil and Associated Gas from the Infill Development of the Robertson Clear Fork Unit*

Scenario (acres/producer)	Recoverable Oil (MB)	Recoverable Gas (MMcf)
80 - 40	14,075	7,361
40 - 20	13,882	7,135
20 - 10	8,627	4,521

* From primary and secondary production

Figure 15

Technically Recoverable Oil



VI. ECONOMIC ASSESSMENT OF INCREMENTAL OIL AND ASSOCIATED GAS PRODUCTION FROM BLANKET INFILL DRILLING IN THE ROBERTSON CLEAR FORK UNIT

This section discusses the economics of reserve growth in the Robertson Clear Fork Unit. The economic analysis is used to establish the number of infill wells that can be economically drilled and how much additional oil can be economically recovered under uniform or blanket infill drilling. The analysis also investigates the economics of infill drilling at two stages of depletion in an oil field.

The economic analysis considers infill drilling strategies where each additional infill well provides progressively less incremental reservoir volume contacted (even though greater amounts of net pay can be contacted), and the cost per barrel of oil recovered increases as well spacing decreases. The economics of infill drilling projects were investigated assuming the most common situations - infill drilling in a field currently undergoing a waterflood, and infill drilling in a depleted field after waterflood operations have ceased.

The economic analysis of reserve growth was performed using two ICF-Lewin economic models: an engineering-based oil field costing and field development model, and a standard discounted cash flow financial analysis model.

A. ENGINEERING COSTING AND FIELD DEVELOPMENT MODEL

The engineering-based costing and field development model simulates the development of a "typical" field or pattern by linking oil recovery, costs, and timing of development. In assessing the economics of infill drilling, the model estimates:

- Pre-Development Costs for the additional diagnostics required for comprehensive reservoir definition
- Development Costs for drilling and completing wells and installing production and injection equipment
- Operating and Maintenance Costs for producing oil and associated gas and for maintaining wells and equipment.

The cost data and algorithms are based on sources widely used within the oil and gas industry and include data from the Department of Energy and the American Petroleum Institute, supplemented by quotations from industry. Costs for this analysis are specific to West Texas for the well depths of concern. These costs are expressed in 1986 dollars. In addition, algorithms exist in the model that relate the estimated costs to oil prices and rig utilization. The cost-price algorithms for drilling costs, operating costs, and equipment costs are based on previous work performed for DOE/FE (Kuuskraa et al, 1986 and 1987).

The engineering-based costing and field development model also allows examination of the changes in oil recovery depending upon the stage of field development at the time infill drilling is undertaken. This is performed by analyzing two, alternative infill development scenarios, as discussed below.

1. Undertaking Infill Drilling in a Field Currently Under Waterflood - In this case, the costs of operating and maintaining existing wells and production equipment are incurred by the ongoing waterflood, at the current conditions in the field or unit. Therefore, the economics of an infill program need only reflect the incremental drilling and operating costs associated with the new infill wells. For example, a blanket infill development program designed to decrease well spacing from 80 to 40 acres per producing well would result in an increase in the well count (injectors and producers) from 16 to 32 in a 640-acre section. In a section currently under waterflood, estimating the cost of the infill project would need only reflect the costs of drilling and operating the additional 16 wells.

2. Undertaking Infill Drilling in a Depleted Field - In a depleted field, the assessment of an infill program must include the costs of drilling the new infill wells, of operating the new and existing wells, including required workovers, and of maintaining and operating all production equipment in the field. While the primary phase of the infill program could operate with only the newly drilled infill wells, the waterflood phase would require the operation of both the previously drilled (or redrilled) wells plus the new infill wells. For example, a 640 acre project operating on 80-acre spacing would contain eight injection and eight production wells. The same reservoir, under an infill development program to 40 acres per producing well, would require the drilling of

an additional 16 wells (eight injection and eight production wells). Production from an infill drilling waterflood, continued after conventional production would have ceased to support the workover costs of the 16 existing wells and the maintenance costs of both of the existing wells and the 16 new infill development wells.

B. ECONOMIC AND FINANCIAL ANALYSIS MODEL

The economic and financial analysis model links oil production, investment and operating costs, and oil prices. It considers royalty payments, severance taxes and income taxes to determine operator return on investment. The purposes of the financial model are:

- To account for all cost components and adjust those that are dependent on oil price, including investments and operating costs.
- To capture all transfer payments such as royalties and taxes.
- To represent standard industry accounting practices in determining the after-tax cash flow for each year of the project.

The model develops year-by-year undiscounted and discounted cash flows and provides the minimum required oil or gas sales price to achieve a specified rate of return (ROR). For the Robertson Clear Fork Unit, a 10 percent ROR after tax was assumed necessary to maintain investor interest in the project. This is not to imply this value as a ROR recommendation to operators of infill development projects. The 10 percent ROR value is simply intended as a benchmark for this preliminary assessment of economic potential.

C. ECONOMIC ANALYSIS OF BLANKET INFILL DRILLING IN THE ROBERTSON CLEAR FORK UNIT

The technical analysis for blanket infill drilling established the volumes of target oil in the Robertson Clear Fork Unit that would be technically feasible to recover. The economic analysis builds on this foundation to establish the amount of this oil, on average, that can be recovered economically at a given price.

Since the analysis shows that the economics of an infill project depend greatly on when in the field's stage of development it is undertaken, two different development scenarios were considered, as discussed below.

1. <u>Economic Analysis of Blanket Infill Drilling in an Existing Field Currently Under Waterflood</u> - The results of the economic analysis for the most common development strategy -- implementation of an infill program in a field currently undergoing waterflood operations -- are shown in Table 7. In this scenario, the infill project must only support the cost of drilling, operating, and maintaining the new infill wells; the operating costs associated with existing wells are borne by the current waterflood operations. The analysis shows that a well spacing reduction from 80 to 40 acres per producing well in the Robertson Clear Fork Unit requires a minimum oil price of $7.07 per barrel to be economically feasible. (The price assessed for the associated natural gas, recovered as part of the infill project, is $0.91 per Mcf, assuming that the value of associated gas is 75 percent of that for oil on an energy-equivalent basis.) An additional decrease in well spacing to 20 acres per producing well results in a slight increase in the minimum oil price to $9.52 per barrel (with a gas price of $1.23 per Mcf).

At oil prices less than $10.00 per barrel, the Robertson Clear Fork Unit could be economically drilled to well spacing of 20 acres per producer using a blanket infill development strategy at current field conditions. However, the further infill development on a blanket basis to 10 acres per producer would be economically justified only if the oil price exceeded $50.00 per barrel.

At prices below $10.00 per barrel, incremental economically recoverable oil for an 80 to 40 acre per well development program would be 14,075 MB; an additional 13,882 MB would be economically recoverable at 20 acres per well, resulting in a total recovery potential of 27,957 MB. If oil prices rose substantially from mid 1988 levels, or project economics were enhanced to make additional development to 10 acre spacing feasible, another 8,627 MB of additional recovery would be possible.

Table 7

Economically Recoverable Incremental Oil
Robertson Clear Fork Unit
Blanket Infill Development Program

Ongoing Waterflood

Development Strategy (acres/producer)	Minimum Required Price		Incremental Economically Recoverable Hydrocarbons	
	($/BOE)	($/Mcf)*	Oil (MB)	Gas (MMcf)
80 to 40	7.07	0.91	14,075	7,361
40 to 20	9.52	1.23	13,882	7,135
20 to 10	50.00	6.47	8,627	4,521

* Assuming a gas value of 75% that of oil on an energy-equivalent basis.

2. Blanket Infill Drilling in a Depleted Field - Another common infill drilling scenario is the development of a depleted field, where waterflood operations at current spacing are at or near completion. In the depleted field scenario, the project economics assume that the waterflood phase would require the operation of both the existing and newly drilled wells while the primary recovery phase of the program could operate with only the newly drilled infill wells.

The economic analysis considers two operator options under the depleted field scenario. First, the analysis examines project economics assuming that both primary recovery and waterflood operations are initiated, and the incremental recovery covers the cost of operating both existing and new infill wells. Secondly, the analysis assumes the project pursues only primary oil recovery and would therefore have to support only the costs of drilling and operating new infill production wells.

The results of the analysis are presented in Table 8, and lead to the following conclusions:

- For the depleted field case, an infill program that reduces pattern spacing from 80 to 40 acres per producing well requires a minimum price (at a 10% ROR) of $8.88 per barrel, under primary plus waterflood operations, and would recover 12,452 MB of oil.

- Under primary operations only, the project economics for the same scenario would be less attractive, resulting in a minimum price of $15.56 per barrel, with incremental oil recovery decreasing by 75% to 3,126 MB.

- A further decrease in well spacing to 20 acres per producer under primary and waterflood operations results in recovery of an additional 12,717 barrels of oil with a minimum required price of $12.53 per barrel (assuming $1.62 per Mcf for associated gas). Primary operations only require a minimum price of $56.25 per barrel to recover 2,266 barrels of oil under this development program.

- Operations at well spacings of less than 20 acres per producer exhibit <u>poor economics</u> under all scenarios, requiring over $50.00 per BOE to be economically justified.

This analysis, shows that the potential for mobile oil recovery with blanket infill development utilizing only primary production methods is not economically attractive in the Robertson Clear Fork Unit. Primary production accounts for only a small portion of total potentially recoverable oil. For example, for the infill development program drilling from 80 to 40 acres per producer, primary production accounts for only 25% (3,126 of 12,452 MB) of total potential recovery estimated with full waterflood operations. Despite the increased costs for the waterflood infill development program, the incrementally recoverable oil is sufficient to offset these costs, making waterflood development the economically preferred option in the Robertson Clear Fork Unit for blanket infill drilling in a depleted field. The results for this analysis show a decrease in potential recovery and an increase in the required minimum oil price of up to 31 percent in the depleted field case compared to the ongoing waterflood case.

In summary, the preferred method for blanket infill development in the Robertson Clear Fork Unit would be to initiate infill drilling in conjunction with a well-designed waterflood program in an existing recovery project. Blanket infill drilling is economically justified (down to a spacing

Table 8

Economically Recoverable Incremental Oil
Robertson Clear Fork Unit
Blanket Infill Development Program

Depleted Field

Development Strategy (acres/producer)	Minimum Required Price ($/BOE)	Minimum Required Price ($/Mcf)*	Incremental Economically Recoverable Hydrocarbons: Oil (MB)	Incremental Economically Recoverable Hydrocarbons: Gas (MMcf)
I. Primary Plus Waterflood Operations				
80 to 40	8.88	1.15	12,452	6,513
40 to 20	12.53	1.62	12,717	6,537
20 to 10	56.63	7.32	8,627	4,521
II. Primary Operations Only				
80 to 40	15.56	2.01	3,126	2,000
40 to 20	56.25	7.27	2,266	1,450
20 to 10	100.00	12.93	1,988	1,272

* Assuming a gas value of 75% that of oil on an energy-equivalent basis.

of 20 acres per producer) at oil prices less than $10.00 per BOE. The infill development from 80 to 20 acres per producer results in nearly 28 MMB of incremental oil production and nearly 14.5 Bcf of associated natural gas recovery.

This analysis only examines the economic justification of blanket infill drilling in the Robertson Clear Fork Unit. The selective placement of wells to exploit reservoir heterogeneity and the more favorable sections of the reservoir could substantially improve the economic potential. Given this improvement in project economics, infill drilling in the Robertson Clear Fork Unit to spacing of less than 20 acres per producing well could be economically attractive in selected portions of the field. A targeted infill drilling program would capture a significant portion of the potential oil at each spacing and dramatically decrease the minimum oil price required for project implementation.

VII. POTENTIAL RECOVERY OF THE UNSWEPT MOBILE OIL RESOURCE IN THE CLEAR FORK PLATFORM CARBONATE PLAY

The volume of target oil defines the potential for reserve growth in the Clear Fork Platform Carbonate Play. Target oil is defined as the total unrecovered oil in each field less the immobile residual oil. (The immobile, residual oil is the target for tertiary oil recovery techniques such as gas miscible or chemical flooding.) Target oil can be further subdivided into two categories: 1) uncontacted mobile oil trapped by internal "compartments" or reservoir heterogeneities and 2) bypassed mobile oil; oil that is in pressure communication with existing wellbores but unrecovered by water injection due to small-scale variations in reservoir continuity. The bypassed oil in the contacted portion of the reservoir is primarily the target for permeability contrast reduction or selective recompletion of bypassed zones. The uncontacted mobile oil is primarily the "target" for reserve growth through infill development.

A. TARGET CRUDE OIL AND ASSOCIATED GAS IN THE PLAY

Infill target oil in each field within the Clear Fork Platform Carbonate Play is calculated using a three-step process. First, the volume of immobile oil is estimated using field-specific residual oil saturation values and formation volume factors, and is subtracted from the OOIP to determine original mobile oil in place. Second, the ultimate oil recovery under current operations is estimated and is subtracted from the original mobile oil in place to estimate unrecovered mobile oil (UMO). Third, drainable and floodable continuity functions developed for the Robertson Clear Fork Unit (Barbe and Schnoebelen, 1987) are used to estimate the volume of oil that has been contacted at the current field spacing but has been bypassed. This bypassed oil is subtracted from the UMO to determine the primary infill target oil. This process is summarized mathematically below:

$$\text{Infill Target Oil} = \text{OOIP} - (\text{EUR} + \text{Bypassed Oil} + \text{Immobile Oil}) \quad (2)$$

$$= [(1 - (\text{EUR} + \text{Bypassed Oil})/\text{OOIP}) - (S_{or}/B_o)/(S_{oi})/B_{oi}]\text{OOIP}$$

where:

OOIP	=	Original oil in place, STB
EUR	=	Estimated ultimate recovery under current operations, STB
S_{or}	=	Residual oil saturation to waterflooding, fraction
S_{oi}	=	Initial oil saturation, fraction
B_{oi}	=	Initial formation volume factor, RB/STB
B_o	=	Current formation volume factor, RB/STB

The values for residual oil saturation and the other reservoir parameters for the Clear Fork Platform Carbonate Play fields were obtained from the Texas Railroad Commission files and from original operator data. Where initial oil saturation was not reported the value was assumed to be $(1-S_{wi})$. The estimated ultimate oil recovery (EUR) for the individual fields in the play was estimated by applying decline curve analysis to current oil production on a field-by-field basis. When possible, these values were corroborated by operator contact.

Table 9 shows the values for the initial oil saturation, residual oil saturation, and formation volume factor that serve as input data for the calculation of mobile oil. Table 10 shows the OOIP, mobile oil, estimated ultimate oil recovery, bypassed oil, and infill target oil for each of the 13 fields in the play. The 13 fields encompass a wide range of field sizes; the largest field is Fullerton with 1,135 MMB of original oil in place, followed by Goldsmith (5600) with 768 MMB. Fullerton also contains the greatest volume of infill target oil with 331 MMB, followed by Robertson North (Clear Fork) with 126 MMB.

The delineation of target oil for the Clear Fork Platform Carbonate Play is illustrated in Figure 16. The 13 fields in the play contain a total OOIP of 4,449 MMB of which 2,246 MMB is considered mobile oil. The estimated ultimate recovery from those fields under current (1983) operations is 925 MMB. This leaves a remaining mobile oil in the play of 1,321 MMB. The amount of bypassed mobile oil in the contacted zones that requires improved secondary recovery is 282 MMB.

Table 9

Volumetric Parameters for Calculation of Target Oil Clear Fork Platform Carbonate Play

Field	Initial Oil Saturation (%)	Residual Oil Saturation (%)	Formation Volume Factor Initial (RB/STB)	Formation Volume Factor Current (RB/STB)
Cowden N. (Deep)	83.8	36.2	1.234	1.146
Dollarhide (Clear Fork)	78.5	42.0	1.627	1.380
Flanagan (U. Clear Fork)	73.0	25.0	1.230	1.130
Fullerton	76.2	23.0	1.615	1.206
Goldsmith (Clear Fork)	77.5	33.9	1.458	1.200
Goldsmith (5600)	70.7	33.3	1.431	1.200
Harris	69.4	31.7	1.111	1.040
Keystone (Holt)	71.0	16.1	1.500	1.125
Riley N. (Upper Clear Fork)	67.0	35.0	1.285	1.180
Robertson N. (Clear Fork)	66.5	34.7	1.332	1.188
Sand Hills (Tubb)	66.8	31.0	1.225	1.102
TXL (Tubb)	62.0	30.0	1.300	1.050
Union	77.5	30.0	1.263	1.071

Source: All volumetric data is operator supplied through the Texas Railroad Commission (RRC) files.

Table 10

Distribution of Oil
Clear Fork Platform Carbonate Play

Field	Original Oil In Place (MMB)	Mobile Oil In Place (MMB)	Estimated Ultimate Recovery* (MMB)	Remaining Bypassed Oil** (MMB)	Infill Target Oil+ (MMB)
Cowden N. (Deep)	176	94	47	neg	47
Dollarhide (Clear Fork)	102	38	32	neg	6
Flanagan (U. Clear Fork)	100	63	23	8	32
Fullerton	1,135	676	231	114	331
Goldsmith (Clear Fork)	295	138	61	5	73
Goldsmith (5600)	768	337	216	neg	121
Harris	148	76	43	neg	33
Keystone (Holt)	222	155	39	41	74
Riley N. (U. Clear Fork)	106	46	20	3	23
Robertson N. (Clear Fork)	640	266	67	73	126
Sand Hills (Tubb)	468	227	92	28	107
TXL (Tubb)	191	77	38	neg	39
Union	98	53	16	10	27
Total	4,449	2,246	925	282	1,039

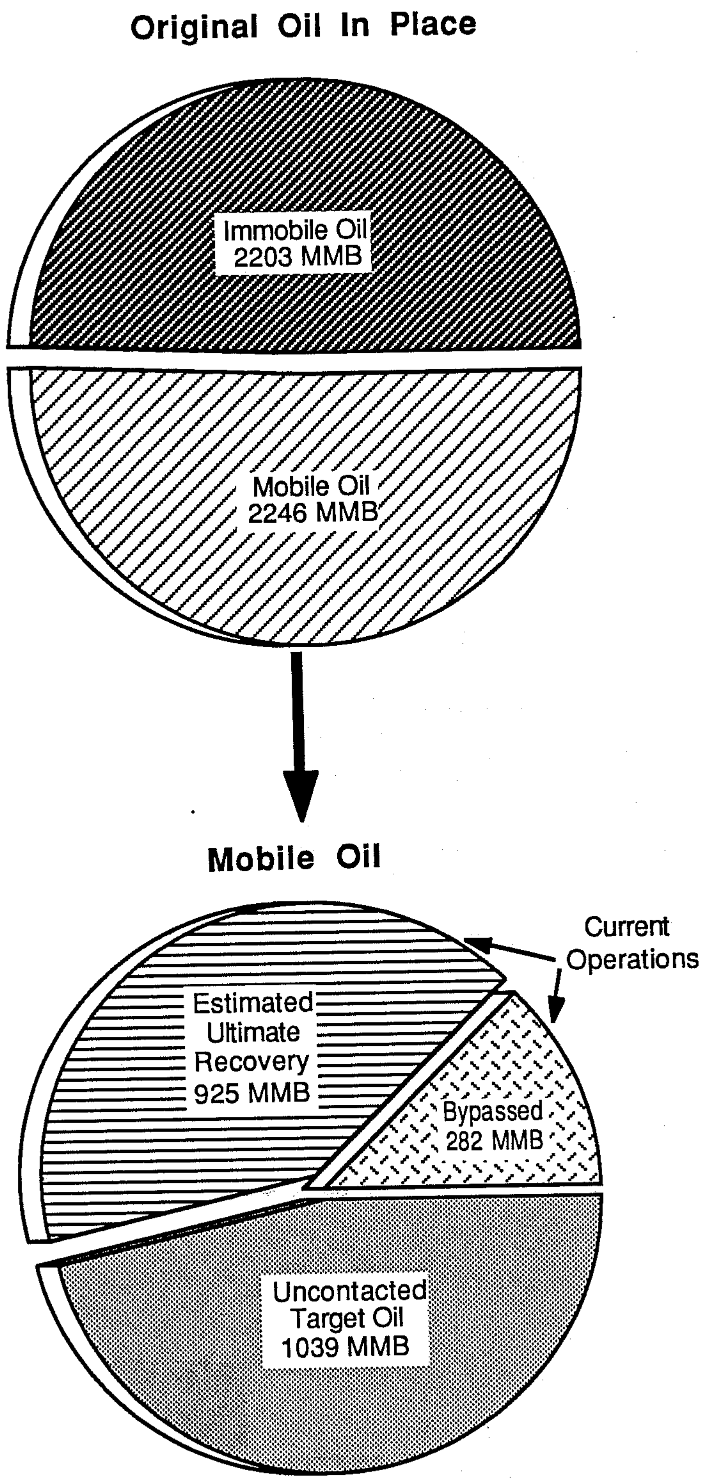
*At end of current operations
**Bypassed oil at current spacing =
(Reservoir Contact (%) * Mobile Oil in Place) - EUR

+Target Oil = Mobile Oil in Place - (EUR + Bypassed Oil)

neg = less than 500,000 barrels

Figure 16

Distribution of Oil in the Clear Fork Platform Carbonate Play



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By subtraction, the remaining "target" mobile oil in place -- the volume of uncontacted or unswept mobile oil in the play which is the "target" of infill development -- is 1,039 MMB.

In addition to crude oil, these 13 fields contain associated (solution) natural gas; solution gas drive is the predominant drive mechanism in this play. Table 11 shows that the total original associated gas in place (OAGIP) for the Clear Fork Platform Carbonate play is 3.30 trillion cubic feet (Tcf). The associated gas volumes in these fields (excluding gas cap volumes) range from 727.5 Bcf in the Fullerton Field, the largest field in terms of the associated natural gas resource, to 23.5 Bcf in the Harris Field, the smallest.

B. EXTRAPOLATION OF RESULTS TO THE PLAY

The concept of geologic analogy serves as the analytical foundation for extrapolating the detailed work on reserve growth in the Robertson Clear Fork Unit to the individual fields of the Clear Fork Platform Carbonate Play. This analysis assumes that the Robertson Clear Fork Unit is geologically representative of the Robertson North Field which is, in turn, geologically analogous to the other fields in the play. In this analysis, no attempt was made to verify the concept of geologic analogy; the concept was assumed to be true for purposes of extrapolation to estimate the potential of the play.

Using the concept of geologic analogy, the reserve growth potential for the individual fields in the play is estimated using a two-step process. First, the reservoir continuity functions and the results of the engineering analysis of the Robertson Clear Fork Unit are combined with the specific properties of each field to establish the remaining recoverable mobile oil in each field. Second, the results from the individual fields are summed to establish the total growth potential for the Clear Fork Platform Carbonate Play.

The following section describes the methodology and discusses the results of the extrapolation of the detailed analysis of the Robertson Clear Fork Unit to the entire play, and presents the overall price/supply curves for economic recovery of unswept mobile oil and associated natural gas in the play.

Table 11

Distribution of Original Associated Gas In Place (OAGIP)
Clear Fork Platform Carbonate Play

Field	Initial Solution GOR (Scf/B)	OAGIP (Bcf)
Cowden N. (Deep)	283	49.8
Dollarhide (Clear Fork)	545	55.6
Flanagan (U. Clear Fork)	450	45.0
Fullerton	641	727.5
Goldsmith (Clear Fork)	1,097	323.6
Goldsmith (5600)	829	636.7
Harris	159	23.5
Keystone (Holt)	863	191.6
Riley N. (Upper Clear Fork)	344	36.5
Robertson N. (Clear Fork)	640	409.6
Sand Hills (Tubb)	1,164	544.8
TXL (Tubb)	1,198	228.8
Union	261	25.6
Total		3,298.6

*Limited gas cap present in field; OAGIP does not include gas cap volume.

Fork Unit between initial oil saturation (0.708), oil saturation at start of waterflood (0.52), and residual oil saturation (0.34). This relationship is demonstrated in the following equation:

$$(S_{oi}-S_o)/(S_{oi}-S_{or}) = \text{relative difference between } S_{oi} \text{ and } S_o \qquad (3)$$

where:

S_{oi} = initial oil saturation, fraction

S_o = current oil saturation, fraction

S_{or} = residual oil saturation, fraction

Substituting the appropriate values into the equation results in the following:

$$(0.708 - 0.52)/(0.708-0.34) = 0.511 \qquad (4)$$

Therefore, the oil saturation at the start of waterflood in each field was calculated to be 51.1 percent of the difference between the initial and the residual oil saturations.

The amount of recoverable oil through blanket infill drilling was estimated from current field spacing as established by current field rules, to 10 acre spacing. Nine of the Clear Fork Platform Carbonate Play Fields have field-wide acreage spacing set at 40 acres, and four have spacing of both 40 and 20 acres. However, operators currently have the option to drill down to 20 acre spacing in some portion of four of the fields, and to 10 acre spacing in some portion of four other fields. These exceptions to the field-wide ruling of 40 acre spacing are allowed by the Railroad Commission as long as the total field spacing average is not below 40 acres. The fact that operators have applied to the RRC to infill drill down to 20 and 10 acres in targeted areas of certain fields clearly suggests that these areas are better than average candidates for infill drilling. High reservoir production trends may ultimately be tied to the deposition and diagenesis of the reservoir rock, indicating the necessity of research to quantify geologic variables in the Clear Fork Platform Play as they relate to production.

The first step of the extrapolation involves the calculation of primary and secondary mobile oil in place in each field, determined by use of the following equations:

$$\text{Primary mobile oil} = OOIP*(B_{oi}/S_{oi})*[(S_{oi}/B_{oi})-(S_o/B_o)] \quad (5)$$

$$\text{Secondary mobile oil} = OOIP*(B_{oi}/S_{oi})*[(S_o-S_{or})/B_o] \quad (6)$$

where:

$OOIP$ = Original oil in place, STB

B_{oi} = Initial formation volume factor, RB/STB

B_o = Current formation volume factor, RB/STB

S_{oi} = Initial oil saturation, fraction

S_o = Oil saturation at beginning of waterflood, fraction

S_{or} = Residual oil saturation, fraction.

The second step involves utilization of the drainable and floodable continuity functions to establish the amount of additional mobile oil that would be contacted by more intensive drilling from the field's current spacing to 10 acres per producer. The additional primary oil is estimated by multiplying the incremental fractional increase on the drainable curve (when moving from current spacing to 10 acre spacing) by the original primary mobile oil in place. The additional secondary oil is estimated by a) multiplying the floodable curve incremental fractional increase times the original secondary mobile oil in place, and then b) multiplying that value by 0.58, the vertical sweep efficiency value established in the Robertson Clear Fork waterflood analysis. The vertical sweep efficiency value reflects the impact of vertical heterogeneity of the reservoir, which results from preferential water channeling through higher permeability zones. Although a wide range in vertical sweep efficiency is possible in the play, the concept of geologic analogy serving as the basis for this analysis assumes that the 58% vertical sweep efficiency is representative, on average, of all of the fields in the play.

Since the waterflood operations modeled in this analysis require two wells per pattern, the injector-producer well pair spacing is less than producer-producer well pair spacing. For example, when producing wells are located at 40 acres, the interwell distance for producer-injector well pairs is 20 acres. This difference is accounted for when establishing incremental increases in continuity.

That is, a 40 to 20 acre per producer incremental net pay continuity increase would apply to an incremental increase in primary mobile oil (drainable curve), which would be accompanied by a 20 to 10 per well acre incremental net pay continuity increase for secondary mobile oil (floodable curve).

The steps applied in this methodology are outlined in Table 12, as a sample extrapolation from the Robertson Clear Fork Unit to the Cowden North (Deep) Field.

2. Recoverable Oil and Associated Gas Estimates - The recoverable oil from blanket infill drilling and development for the Clear Fork Platform Carbonate Play is estimated to be 308 MMB, if well spacing is decreased from current individual field levels to 10 acres per producing well. This amount represents 6.9 percent of the original oil in place in the play and 29.6% of the infill target oil at the end of current operations (1,039 MMB). Table 13 presents the results of this analysis for each field. Table 14 summarizes the technical recovery potential of infill drilling for all fields from current spacing to 20 acres per producer and ultimately to 10 acre spacing.

In addition to the 308 MMB of recoverable oil from infill drilling, 156 MMB are contacted but bypassed due to the inherent geologic vertical heterogeneity of the individual fields (Figure 17). This oil, along with the 282 MMB of oil bypassed by current waterflood operations, is primarily the target for extended secondary recovery techniques, such as permeability contrast reduction or selective well recompletion. At less than 10-acre spacing, there remains a considerable volume, 575 MMB, of uncontacted mobile oil left unrecovered.

With the more intensive development of the Clear Fork Platform Carbonate Play oil fields, significant volumes of associated natural gas will also be recovered. Blanket infill programs designed to decrease spacing from current levels to 10 acres per producing well in the play could potentially recover 187.2 Bcf of gas. This figure represents 5.7% of the original associated gas in place (OAGIP) in the 13 fields.

3. Economic Analysis - The economic analysis for the blanket infill development of the Robertson Clear Fork Unit was conducted to establish the minimum oil price required at various well spacings to yield a 10 percent ROR. These results were used to estimate economically

Table 12

Sample Calculation of Reserve Growth Potential Cowden N. (Deep) Field

<u>Basic Data</u>

OOIP:	176.0 MMB
Mobile Oil:	94.0 MMB

Theoretically Recoverable:

- Primary Mobile Oil: 41.0 MMB
- Secondary Mobile Oil: 53.0 MMB

<u>Oil Saturations</u>

Initial: 83.8%
Waterflood: 59.5%
Residual: 36.2%

<u>Formation Volume Factors</u>

Initial: 1.234 RB/STB
Latest: 1.146 RB/STB

Field Well Spacing: 40 acres per producer

<u>Reserves Growth Estimate</u> - Blanket Infill Development from 40 Acres to 10 Acres Per Producer

Incremental Primary Reservoir Contact: 15.0%
Incremental Floodable Reservoir Contact: 27.0%

Infill Primary Recovery:	0.150 * 41.0 MMB	=	6.2 MMB
Infill Secondary Recovery:	0.27 * 0.58 * 53 MMB	=	8.3 MMB
Total Blanket Infill Recovery:			14.5 MMB

Table 13

Reserve Growth Potential of the Clear Fork Platform Carbonate Play*

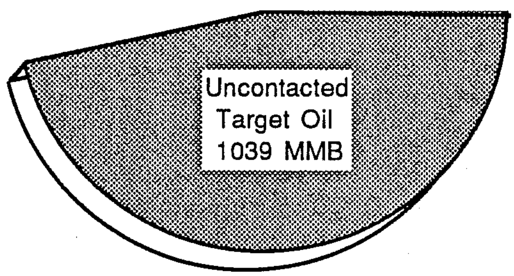
Field	Current Well Spacing (acres/producer)	Recoverable Hydrocarbons Crude Oil (MMB)	Recoverable Hydrocarbons Natural Gas (Bcf)
Cowden N. (Deep)	40	15	3.6
Dollarhide (Clear Fork)	40	6	2.6
Flanagan (U. Clear Fork)	40	10	3.8
Fullerton	30**	85	44.6
Goldsmith (Clear Fork)	40	21	19.5
Goldsmith (5600)	40	52	36.0
Harris	40	12	1.6
Keystone (Holt)	30**	19	13.9
Riley N. (Upper Clear Fork)	40	7	2.1
Robertson N. (Clear Fork)	30**	33	18.0
Sand Hills (Tubb)	30**	28	28.1
TXL (Tubb)	40	12	11.6
Union	40	8	1.8
Total		308	187.2

*Assuming infill drilling from current well spacing to 10 acres per producer.
**Average well spacing in fields that have both 40 acre and 20 acre options to drill.

Figure 17

Clear Fork Platform Carbonate Play Target Oil From Current Spacing to 10-Acre Spacing Through Blanket Infill Drilling

Current Spacing



Current Spacing to 10-Acre Spacing

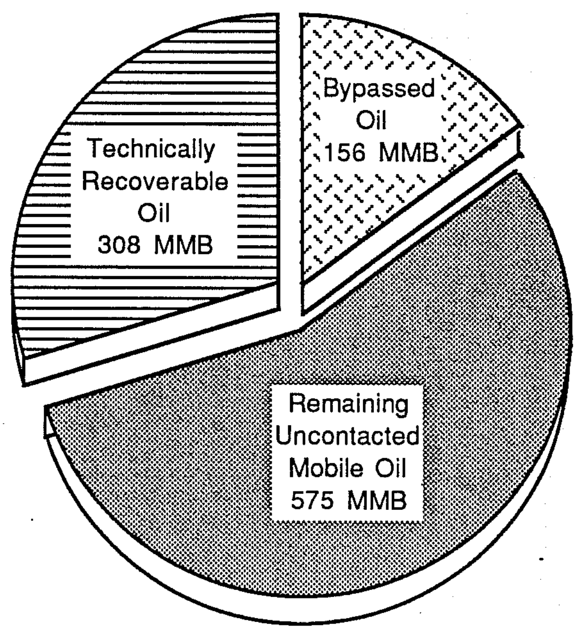


Table 14

Reserve Growth Potential of the Clear Fork Platform Carbonate Play

Development Strategy (acres/producer)	Recoverable Hydrocarbons Crude Oil (MMB)	Recoverable Hydrocarbons Natural Gas (Bcf)
40 to 20	169	152.8
20 to 10	139	122.4
Total	308	275.2

recoverable hydrocarbon reserve additions from blanket infill drilling in the Clear Fork Platform Carbonate Play and to develop an overall price/supply curve for blanket infill drilling in the play.

The rate of oil production varies considerably with field permeability, which controls both the injection of fluids and the flow of oil through the reservoir. Consequently, the economic analysis was conducted for three different permeability categories -- less than 10 md, 10 to 20 md, and greater than 20 md -- in order to capture possible differences in rates of fluid flow, and the effect of these differences on overall project economics. Therefore, the fields in the Clear Fork Platform Carbonate Play were divided into distinct permeability categories. Table 15 displays the recoverable oil and gas, and the average reservoir permeability for each of the 13 fields analyzed. The average reservoir permeability range from a low of 1 md in the TXL (Tubb) Field to a high of 58 md in the Keystone (Holt) Field, with an average for the play of close to 14 md. Each field was assigned to one of the three permeability categories analyzed.

An analysis was performed that considered the impact of the variation in average permeability on the economics of oil recovery in the Robertson Clear Fork Unit. This sensitivity

Table 15

Reserve Growth Potential of the Clear Fork Platform Carbonate Play*

			Recoverable Hydrocarbons	
Field	Crude Oil (MMB)	Natural Gas (Bcf)	Average Permeability (md)	Permeability Category
Cowden N. (Deep)	15	3.6	7	1
Dollarhide (Clear Fork)	6	2.6	10	2
Flanagan (U. Clear Fork)	10	3.8	3	1
Fullerton	85	44.6	3	1
Goldsmith (Clear Fork)	21	19.5	5	1
Goldsmith (5600)	52	36.0	25	3
Harris	12	1.6	11	2
Keystone (Holt)	19	13.9	58	3
Riley N. (U. Clear Fork)	7	2.1	12	2
Robertson N. (Clear Fork)	33	18.0	19	2
Sand Hills (Tubb)	28	28.1	30	3
TXL (Tubb)	12	11.6	1	1
Union	8	1.8	2	1
Total	308	187.2	avg = 14 md	

*Assuming infill drilling from current well spacing to 10 acres per producer.

analysis was constructed to determine the change in recovery performance predicted for the Robertson Clear Fork Unit at average permeabilities above and below the actual value for the reservoir. This evaluation used the same models and data, varying only average reservoir permeability, to determine the change in the minimum oil and gas prices required to support infill development to various reduced well spacings. The results of the sensitivity analysis are shown in Table 16 for infill development initiated in ongoing waterflood projects. The analysis for Category 2 (greater than 10 md and less than 20 md), by definition, is the same as that determined in the unit analysis discussed previously. At lower permeabilities (Category 1, less than 10 md), project economics of blanket infill drilling are less attractive, requiring higher minimum prices to economically justify development. In reservoirs with higher average permeabilities (Category 3, greater than 20 md), blanket infill development is economic at lower oil and gas prices than for the other two categories.

The extrapolation methodology utilizes these results to determine the play-wide recovery potential at various oil prices. The play-level extrapolation considered volumes of recoverable unswept mobile oil and the average permeability in each of the 13 fields and applied the results of the sensitivity analysis to determine recovery potential at various oil prices. The analysis assumes that once the required minimum oil price is determined to support blanket development of a given permeability category to a reduced well spacing, all reservoirs in that category are fully developed. The economic recovery potential projected in the play is the sum of recovery from all 13 fields developed to the minimum spacing possible at a given oil price.

The extrapolation of the detailed economic analysis of the fields of the Clear Fork Platform Carbonate Play shows that at prices of about $20.00 per barrel, a total of 170 MMB of oil (plus 100 Bcf of associated natural gas) are recoverable by blanket infill drilling from current field spacings down to 10 acres per producer. Thus, 16 percent of the infill target mobile oil in place (1,039 MMB) is economic to produce from blanket infill drilling at current oil prices. Therefore, the economic analysis of the Clear Fork Platform Carbonate Play shows that even under the current oil prices of less than $20.00 per barrel, a significant amount of oil recovery can be realized with blanket infill drilling. At $30.00 per BOE, an additional 40 MMB (plus 40 Bcf of associated natural gas) of oil may be economically recovered, at a 10 percent ROR, bringing the total recoverable oil to 210 MMB (plus 140 Bcf of associated natural gas). On the other hand, at $10 per barrel of oil,

Table 16

Economically Recoverable Incremental Oil Robertson Clear Fork Unit - Blanket Infill Development Program for the Three Permeability Categories

Ongoing Waterflood

Permeability Category	Development Strategy (acres/producer)	Minimum Required Price ($/BOE)	Minimum Required Price ($/Mcf)*
1 (≤10 md)			
	80 - 40	11.49	1.49
	40 - 20	18.70	2.42
	20 - 10	66.33	8.58
2 (10 - 20 md)			
	80 - 40	7.07	0.91
	40 - 20	9.52	1.23
	20 - 10	50.00	6.47
3 (≥20 md)			
	80 - 40	4.96	0.64
	40 - 20	7.96	0.93
	20 - 10	28.61	3.70

*Assuming a gas value of 75% that of oil on an energy-equivalent basis.

the reserve growth potential for the play is reduced to 95 MMB (plus 60 Bcf of associated natural gas). The reserve growth potential from blanket infill drilling for the Clear Fork Platform Carbonate Play is illustrated in Table 17 and in aggregate in the price/supply curves in Figures 18 and 19 for incremental crude oil and associated natural gas, respectively.

Table 17

Estimated Economically Recoverable Hydrocarbons from Blanket Infill Development for Various Price Ranges

Development Strategy (acres/producer)	Price Range ($/Bbl)								Total	
	<$10.00		$10.00-$20.00		$20.00-$30.00		>$30.00			
	MMB	(Bcf)	MMB	(Bcf)	MMB	(Bcf)	MMB	(Bcf)	MMB	(Bcf)
40 to 20	95	(60)	75	(40)	-	-	-	-	170	(100)
20 to 10	-	(-)	-	(-)	40	(40)	80	(35)	120	(75)
Total	95	(60)	75	(40)	40	(40)	80	(35)	290	(175)

Note: Numbers in parenthesis are recoverable associated natural gas.

Figure 18

Price/Supply Curve
Oil Recovery From Blanket Infill Drilling
Clearfork Platform Carbonate Play
(Ongoing Waterflood Scenario)

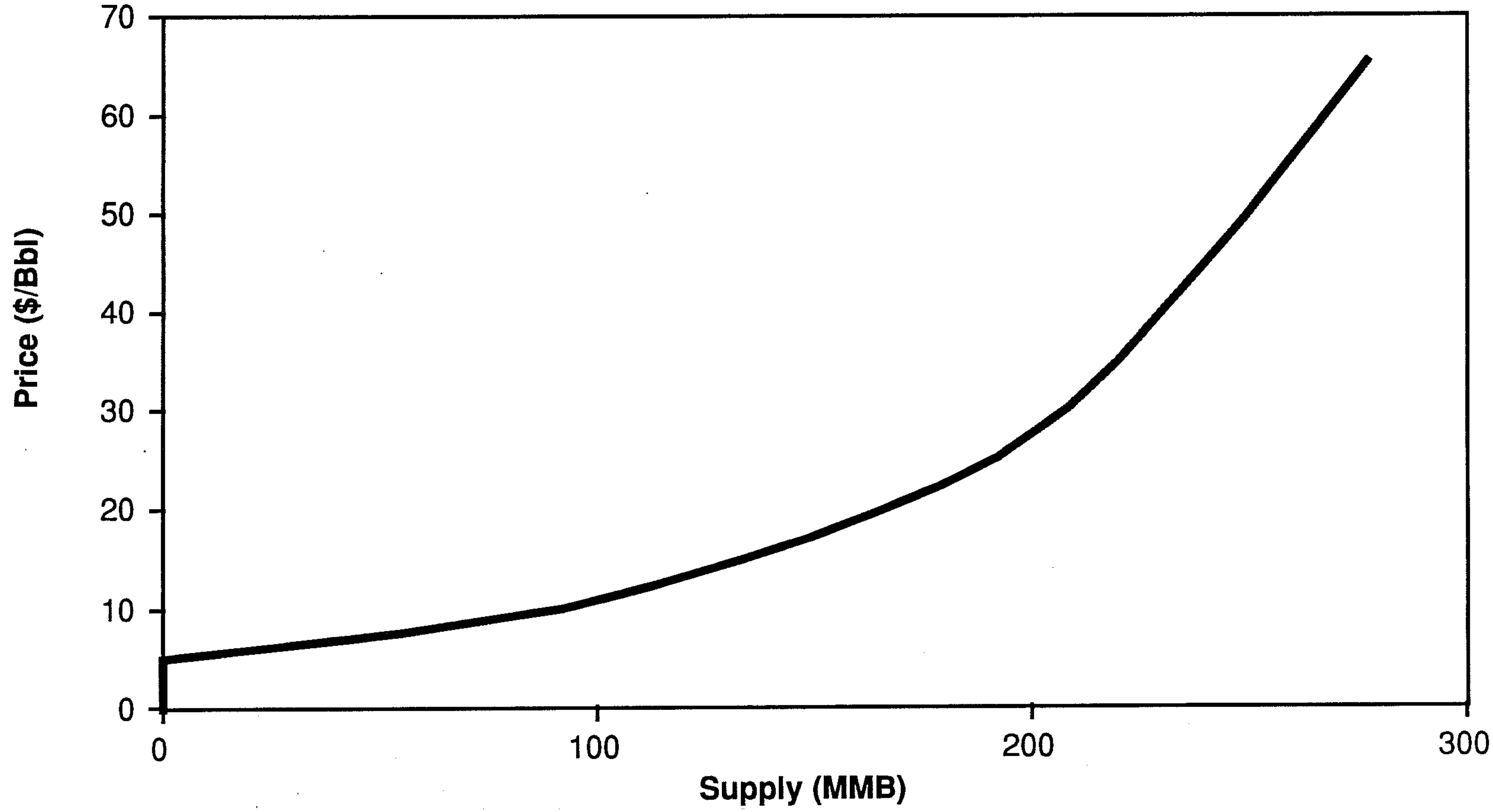


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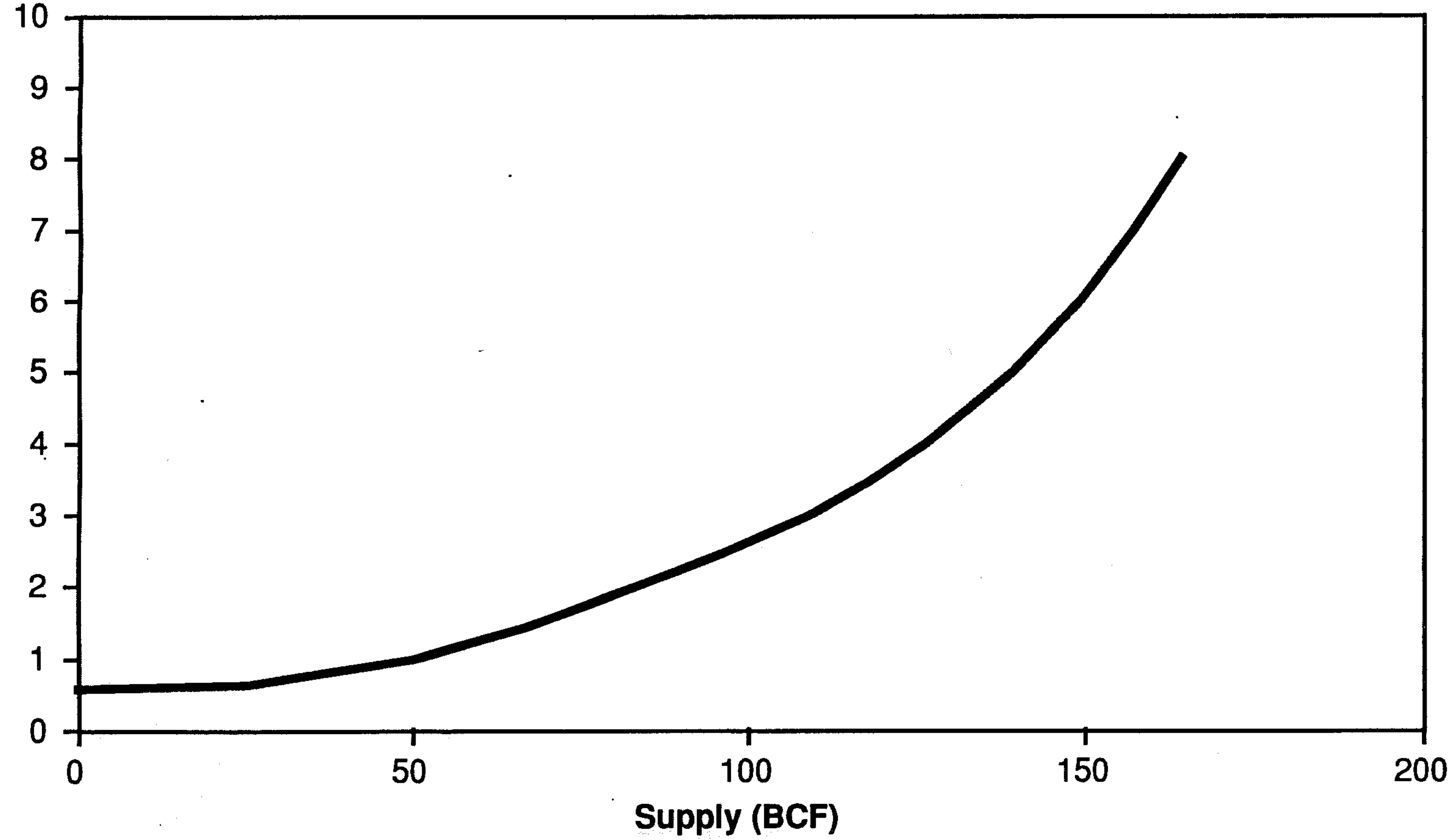
Figure 19

Price/Supply Curve
Gas Recovery From Blanket Infill Drilling
Clearfork Platform Carbonate Play
(Ongoing Waterflood Scenario)



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VIII. CONCLUSIONS

The results of this study show that significant potential exists for the recovery of the unswept mobile oil resource through infill drilling in the Clear Fork Platform Carbonate Play in West Texas. Under a uniform blanket infill development program to 10 acres per producer, at oil prices less than $20 per barrel (in 1986 dollars), approximately 170 MMB of previously uncontacted oil and 100 Bcf of associated natural gas could potentially be recovered. An additional 40 MMB of oil and 40 Bcf of natural gas becomes economic to produce at an oil price of $30 per barrel.

Crude oil prices and the timing of infill drilling govern the economics of blanket development in the Clear Fork Platform Carbonate Play. The timing of infill development is critical for fulfilling maximum economic potential, as was clearly demonstrated in this report through the analysis of the Robertson Clear Fork Unit, which was considered to be representative of the play. At oil prices close to $10 per barrel, approximately 28 MMB of oil and 14 Bcf of natural gas would be economic to produce if the infill development program was initiated in an ongoing waterflood at an 80-acre pattern, with economic development feasible to a 20 acre pattern. However, if infill development was not initiated until waterflood operations ceased on the 80-acre pattern, only 12 MMB of oil and 6.5 Bcf of natural gas would be economic to produce at a $10 per barrel oil price, with economic infill development feasible only to a 40-acre waterflood pattern.

An additional hydrocarbon resource in the Clear Fork Platform Carbonate Play is the mobile oil that is contacted in the course of drilling, but bypassed due to vertical heterogeneity in the reservoirs. The play has an estimated 282 MMB of mobile oil that is currently contacted but bypassed, and an additional 156 MMB of mobile oil that would be contacted, but bypassed, under a blanket infill drilling program to 10 acres per producer. This bypassed oil would be the target for improved secondary recovery techniques such as permeability contrast reduction and selective zone recompletion. An additional 2.2 billion barrels of immobile oil, the target for enhanced oil recovery methods, is also contained in the fields of this play.

Blanket infill drilling could recover a significant volume of oil in the Clear Fork Platform Carbonate Play at low oil prices. However, the implementation of geologically targeted or strategic infill drilling could limit the required investment and lead to an appreciable addition in oil reserves at lower oil prices. This approach for recovering mobile oil can also limit operator risk, further enhancing the economic recovery in this important play.

Fundamental to the analysis presented in this report is the concept of geologic analogy. This concept served as the analytical foundation for the analysis, since the concept is based on the assumption that the Robertson Clear Fork Unit is geologically analogous to the Robertson North Field, which is, in turn, geologically analogous to the other fields in the play. No attempt was made to verify this assumption in this analysis, though verification is recommended for future studies.

Additional research is critical to maximizing recovery of unswept mobile oil. With a coordinated program to reduce costs and alter operator risk, oil recovery by infill drilling in the Clear Fork Platform Carbonate Play could be substantially higher than estimated here. In addition to the unswept mobile oil target for extensive infill development, an overall program to also increase recovery of immobile and bypassed oil could result in the additional economic recovery of up to 500 million barrels of crude oil.

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APPENDIX
GLOSSARY OF GEOLOGIC TERMS

anticline. In its simplest form, an anticline is an elongated fold in which the sides or limbs slope downward away from the crest. This simple form may be greatly complicated during progressive stages of folding. In a normal sequence of bedded rocks, the oldest beds are in the core of the anticline and the youngest lie on the flanks.

barrier bar. A narrow elongate sand ridge rising slightly above high-tide level and extending generally parallel with the coast, but separated from it by a lagoon. Modern examples are Galveston Island on the Texas Gulf Coast and Cape Hatteras on the Atlantic Coast.

carbonates. Mineral compounds characterized by a fundamental anionic structure of CO_3^{-2}. Calcite and aragonite, $CaCO_3$, are examples of carbonates.

chenier. a long, narrow, wooded beach ridge or sandy hummock, 3 to 6 m high, forming roughly parallel to a prograding shoreline seaward of marsh and mud-flat deposits (as along the coast of southern Louisiana), enclosed on the seaward side by fine-grained sediments, and resting on peat or clay.

clastics. Pertaining to rocks or sediments composed principally of fragments derived from pre-existing rocks or minerals and transported some distance from their places of origin. The most common clastics are sandstone and shale.

deposition. The act or process of accumulating natural materials into sediments. Deposition includes mechanical settling of material from bodies of water and ice or from the air, and the accumulation of organic material through the life processes of plants and animals.

depositional system. A group of facies linked by a depositional environment and associated processes.

diagenesis. All changes undergone by a sediment after its initial deposition, exclusive of metamorphism. It includes processes (such as compaction, cementation, dissolution, and replacement) that occur under conditions of pressure and temperature that are normal at shallow depths in the outer part of the earth's crust.

Note: The definitions supplied in Appendix A are drawn primarily from: Stokes, W.L. and Varnes, D.J., 1955 "Glossary of Selected Geologic Terms", Colorado Scientific Society; Bates, R.L., and Jackson, J.A. (eds.), 1984 "Dictionary of Geological Terms," 3rd ed., American Geological Institute; Reineck, H.E., and Singh, I.B., 1980, Depositional Sedimentary Environments, 2nd ed., Springer-Verlag.

dolomitization. The process by which limestone is converted to dolomite rock or dolomitic limestone by the replacement of the original calcium carbonate (calcite) by magnesium carbonate (mineral dolomite) through the interaction with magnesium-bearing waters.

echinoderm. Any solitary marine bottom-dwelling invertebrate, belonging to the phylum Echinodermata, characterized by radial symmetry, an endoskeleton formed of plates or ossicles of crystalline calcite, and a water-vascular system.

eolian. Pertaining to the wind; especially said of such deposits as dune sand, or of erosion and deposition accomplished by the wind.

evaporite. One of the sediments which are deposited from aqueous solution as a result of extensive or total evaporation.

facies. A facies is a three-dimensional body of rock whose environmental origin can be inferred from a set of observable characteristics. The features on which facies are named and recognized are usually lithologic (lithofacies) or biologic (biofacies). The lithologic designation predominates in this report. The term applies to a specific rock unit; a facies within the specific unit then designates some particular or general feature by which a part differs from other parts deposited at the same time. Example: deltaic facies of the Green River Formation.

formation. A body of rock strata that consists dominantly of a certain lithologic type or combination of types.

fusulinid. Any of an important group of extinct, marine, one-celled animals (Class Sarcodina, Phylum Protozoa) that have left an extensive fossil record for late Paleozoic time. Fusulinids are characterized by a multi-channeled calcareous test, commonly resembling a grain of wheat. Because of their small size, they are easily recovered from well cuttings and have proved of great value in correlation of oil-bearing Pennsylvanian and Permian age rocks.

grainstone. A grain-supported sedimentary carbonate rock containing no mud.

intergranular porosity. Porosity that occurs between sediment or rock grains (or particles) found in both carbonates and clastics. This type of porosity may be found as void space between ooids, pellets, or skeletal grains in carbonate rocks, and between small sand grains to pebble-sized grains in clastics.

intertidal. The depositional environment in a coastal area that lies within normal high and low tide, with sediments being exposed once or twice daily (depending on the tidal regime or local winds).

lithology. The description of rocks on the basis of such characteristics as color, mineralogic composition, grain size, grain type, and grain distribution.

moldic porosity. Secondary porosity formed by the selective removal of mineral constituents from sediment or rock; includes removal of constituents from the framework of fossils, from inorganic grains such as ooids, and the dissolution of evaporite minerals from the surrounding sediment or rock.

mollusk. A solitary invertebrate belonging to the phylum Mollusca, characterized by a nonsegmented body that is bilaterally symmetrical and by a radially or biradially symmetrical mantle and shell. Among the classes included in the mollusks are the gastropods, pelecypods, and cephalopods.

mudstone. A mud-supported sedimentary carbonate rock containing less than ten percent grains.

offlap. The progressive offshore movement of the updip edges of sedimentary units within a conformable sequence of rocks, in which each successively younger unit leaves exposed a portion of the older unit on which it lies.

onlap. The progressive pinching out of sedimentary units within conformable sequence of rocks toward the margins or shores of a depositional basin, in which the boundary of each unit is covered by the next, younger unit, and each new unit in turn terminates farther from the point of reference.

oil play. A family of oil reservoirs or fields sharing a common geologic history as defined by present day reservoir similarities. The most important parameters in play definition are reservoir origin, trap style, and source rocks. Basic geologic, engineering, and production attributes are also considered in the designation of a play. The importance of a play is that its component fields are considered a geologic "unit" from which play to play comparisons can be made.

oolite. A sedimentary rock, usually a limestone or dolostone, made up of small, rounded accretionary bodies, or ooliths, cemented together. Ooliths resemble fish eggs, with a diameter of 0.25 to 2.0 mm. The concentric coatings of these grains precipitate inorganically around a nucleus.

packstone. A grain-supported sedimentary carbonate rock containing some matrix of carbonate mud.

pellet. A small rounded aggregate of sedimentary material, such as a fecal pellet.

sabkha. An environment of sedimentation on a coastal plain just above normal high-tide level, formed under arid to semiarid conditions. This environment is commonly characterized by evaporite-salt, tidal-flood, and windblown deposits.

sediment. Solid, natural material that has settled down from a state of suspension in water, air, or ice.

shale. A fine-grained detrital sedimentary rock, formed by the compaction of clay, silt, or mud.

shelf. A stable and commonly flat cratonic area often flooded by marine waters and receiving deposition of sediments.

shoal. A submerged ridge, bank, or bar of sand or other unconsolidated material, rising from the bed of a body of water to near the water surface.

spit. A small point of sand or gravel projecting from the shore into a body of water; a fingerlike extension of a beach.

subtidal. The depositional environment in a coastal tidal area in which the sediments that are deposited are continuously submerged in water.

supratidal. The depositional environment in a coastal area that is above normal high tide. This environment is exposed to the air the majority of the time, with flooding only from spring tides (twice each month) and storm tides.

tectonics. A branch of geology dealing with the broad architecture of the outer part of the earth, that is, the major structural or deformational features and their relations, origin, and historical evolution.

tidal flat. An extensive, nearly horizontal, marshy or barren tract of land that is alternately covered and uncovered by the tide, and consisting of unconsolidated sediment.

transgression. The spread of the sea over land areas; also, any change that brings offshore, deep-water environments to areas formerly occupied by nearshore, shallow-water conditions, or that shifts the boundary between marine and nonmarine deposition outward from the center of a marine basin.

wackestone. A mud-supported sedimentary carbonate rock containing greater than ten percent grains (particles with diameters greater than 0.2 mm).

wadi. Sporadic water courses in deserts, sometimes resulting in fanlike features (commonly referred to as alluvial fans).