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REVITALIZING A MATURE OIL PLAY: STRATEGIES FOR FINDING AND PRODUCING UNRECOVERED OIL IN FRIO FLUVIAL-DELTAIC SANDSTONE RESERVOIRS OF SOUTH TEXAS

Final Report

By
Paul R. Knox, Mark H. Holtz, Lee E. McRae,
Tucker F. Hentz, Jeffrey G. Paine, W. Gerald White,
and Chun-Yen Chang

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ABSTRACT

Domestic fluvial-dominated deltaic (FDD) reservoirs contain more than 30 Billion barrels (Bbbl) of remaining oil, more than any other type of reservoir, approximately one-third of which is in danger of permanent loss through premature field abandonments. The U.S. Department of Energy has placed its highest priority on increasing near-term recovery from FDD reservoirs in order to prevent abandonment of this important strategic resource. To aid in this effort, the Bureau of Economic Geology, The University of Texas at Austin, began a 46-month project in October, 1992, to develop and demonstrate advanced methods of reservoir characterization that would more accurately locate remaining volumes of mobile oil that could then be recovered by recompleting existing wells or drilling geologically targeted infill wells.

Reservoirs in two fields within the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) oil play of South Texas, a mature play which still contains 1.6 Bbbl of mobile oil after producing 1 Bbbl over four decades, were selected as laboratories for developing and testing reservoir characterization techniques. Advanced methods in geology, geophysics, petrophysics, and engineering were integrated to (1) identify probable reservoir architecture and heterogeneity, (2) determine past fluid-flow history, (3) integrate fluid-flow history with reservoir architecture to identify untapped, incompletely drained, and new pool compartments, and (4) identify specific opportunities for near-term reserve growth. To facilitate the success of operators in applying these methods in the Frio play, geologic and reservoir engineering characteristics of all major reservoirs in the play were documented and statistically analyzed. Finally, to assist operators in identifying those reservoirs most prospective for reserve growth, and therefore most worthy of detailed characterization efforts, a quantitative quick-look methodology was developed to prioritize reservoirs in terms of reserve-growth potential.

Extensive efforts have been made to transfer the methodology and results of this study to operators within the Frio play, as well as to all operators of fluvial-deltaic reservoirs. One half-day and two full-day workshops were held in cities convenient to Frio operators to demonstrate the methodology through lectures and exercises and answer any questions or concerns about its application. Throughout the course of the study, 16 presentations and 15 publications have been completed to keep operators and researchers across the country, as well as the DOE, informed about project progress and results. Additionally, a microcomputer-based software program titled the Reservoir Characterization Advisor—Fluvial-Deltaic (RCA—FD) has captured the integrated reservoir characterization method and results in a user-friendly format that includes opportunities for input and quick-look prioritization evaluation of operator data.

EXECUTIVE SUMMARY

This volume summarizes work done by the Bureau of Economic Geology, The University of Texas at Austin, over a 46-month period as part of the U.S. Department of Energy (DOE) Oil Recovery Field Demonstration Program, Class I (Near-Term). The goal of the program, and this project, is to increase oil production from domestic fluvial-deltaic reservoirs in the near term to prevent their premature abandonment and the resulting permanent loss of resources to the United States. Specifically, this project developed and demonstrated an integrated, multi-disciplinary advanced reservoir characterization methodology that can aid operators in locating areas of untapped or incompletely drained reservoirs. These areas can then be targeted for near-term production through the recompletion of existing wells or the drilling of new infill wells.

Nearly 11 billion barrels (Bbbl) of mobile oil, approximately equivalent to original mobile oil in Prudhoe Bay field of Alaska, remain in domestic fluvial-dominated deltaic reservoirs despite their mature status (personal communication, Mark Young, DOE Bartlesville Project Office, 1996). Approximately 1.6 Bbbl of this resource, approximately 15 percent of the domestic total, reside in reservoirs of the Frio Fluvial-Deltaic Sandstone Play (Vicksburg Fault Zone) in Texas. The project summarized herein has provided operators within this play with models of interwell-scale reservoir architecture and heterogeneity that are supported by specific examples of reserve-growth opportunities within Frio fields. These models are based on integrated geological, geophysical, and engineering characterization of stratigraphically complex Frio reservoirs and are applicable to fluvial-deltaic reservoirs throughout the United States.

A conservative estimate of mobile oil identified during this study of 12 major reservoirs is 4.7 million barrels. Numerous recompletion and infill opportunities have been identified to operators for potential action. Results of the first action by an operator support the validity of project methodology: a recompletion recommended by this study in a well identified as being within an incompletely drained reservoir compartment has yielded economic production rates of 600 thousand cubic ft of gas per day.

The methodology developed and applied in this project requires an investment in personnel time and data acquisition that is substantial for many small operators. As a consequence, operators must make an initial effort to evaluate their reservoirs to determine which ones likely contain significant remaining resources. This project has developed a methodology by which reservoirs can be quickly and semiquantitatively ranked in terms of their reserve growth potential. Parameters used in the evaluation are designed to be readily available to the typical operator, preventing a loss of time in extensive data-gathering efforts. This methodology has been incorporated into the Reservoir Characterization Advisor—Fluvial Deltaic software package as an interactive routine that calculates reservoir priority on the basis of data input by the operator.

The technology and methodology used in this project have been transferred to Texas operators through inexpensive workshops at sites convenient to the majority of companies and through technical presentations and publications at the local level. Presentations at national technical meetings have made technologies and results available to all domestic operators, and the methodology has been made publicly available through production of the Reservoir Characterization Advisor—Fluvial Deltaic (RCA—FD), a software package for use in personal computers.

This project has met its goal of developing and demonstrating an advanced, integrated, multidisciplinary methodology of reservoir characterization to identify opportunities for near-term recovery of resources in fluvial-deltaic reservoirs. The current and expected future success of recompletions and infill wells based on this study provide convincing evidence to operators that detailed integrated characterization can revitalize mature fields and prevent the loss of domestic resources because of premature abandonment of fields.

INTRODUCTION

P.R. Knox and L.E. McRae

Data from the U.S. Department of Energy (DOE) TORIS database indicate that domestic fluvial-dominated deltaic (FDD) reservoirs contain 30 billion barrels (Bbbl) of remaining oil in place, more than almost any other reservoir type, and that more than one-third of this strategic domestic resource is in near-term danger of being lost because of premature field abandonment (Figure 1). As a consequence, the U.S. DOE has placed a high priority on activities that will preserve access to these fields by increasing production in the near future. Texas was identified as the state having the largest near-term incremental recovery potential in such reservoirs (616 million barrels total) (U.S. DOE, 1991, Ch. 2).

To respond to this urgent need for increased production from FDD reservoirs, the Bureau of Economic Geology, The University of Texas at Austin, began a 46-month project in October, 1992, to develop and demonstrate to operators methods that could quickly improve oil production. As a laboratory for demonstration, the Bureau selected the most prolific fluvial-deltaic play on the Texas Gulf Coast, the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone). Because recompletion of existing wells and drilling of infill wells is the most significant and least expensive method for improving production in FDD reservoirs, the Bureau focused its efforts on developing and demonstrating techniques for multidisciplinary advanced reservoir characterization that can identify the location and volume of unrecovered mobile oil and lead to cost-effective reserve growth.

This report summarizes the results of the Bureau's 46-month project. The introductory section is a review of project objectives and approach. In following sections, the methodology developed for integration of geology, geophysics, and engineering in reservoir characterization is demonstrated with selected examples from studied reservoirs. In addition, the distribution of values for geologic and engineering attributes of reservoirs throughout the play is provided to support estimates of the volume of oil resources remaining in the play and the reserve growth potential of reservoirs in the play. Because integrated characterization efforts consume precious

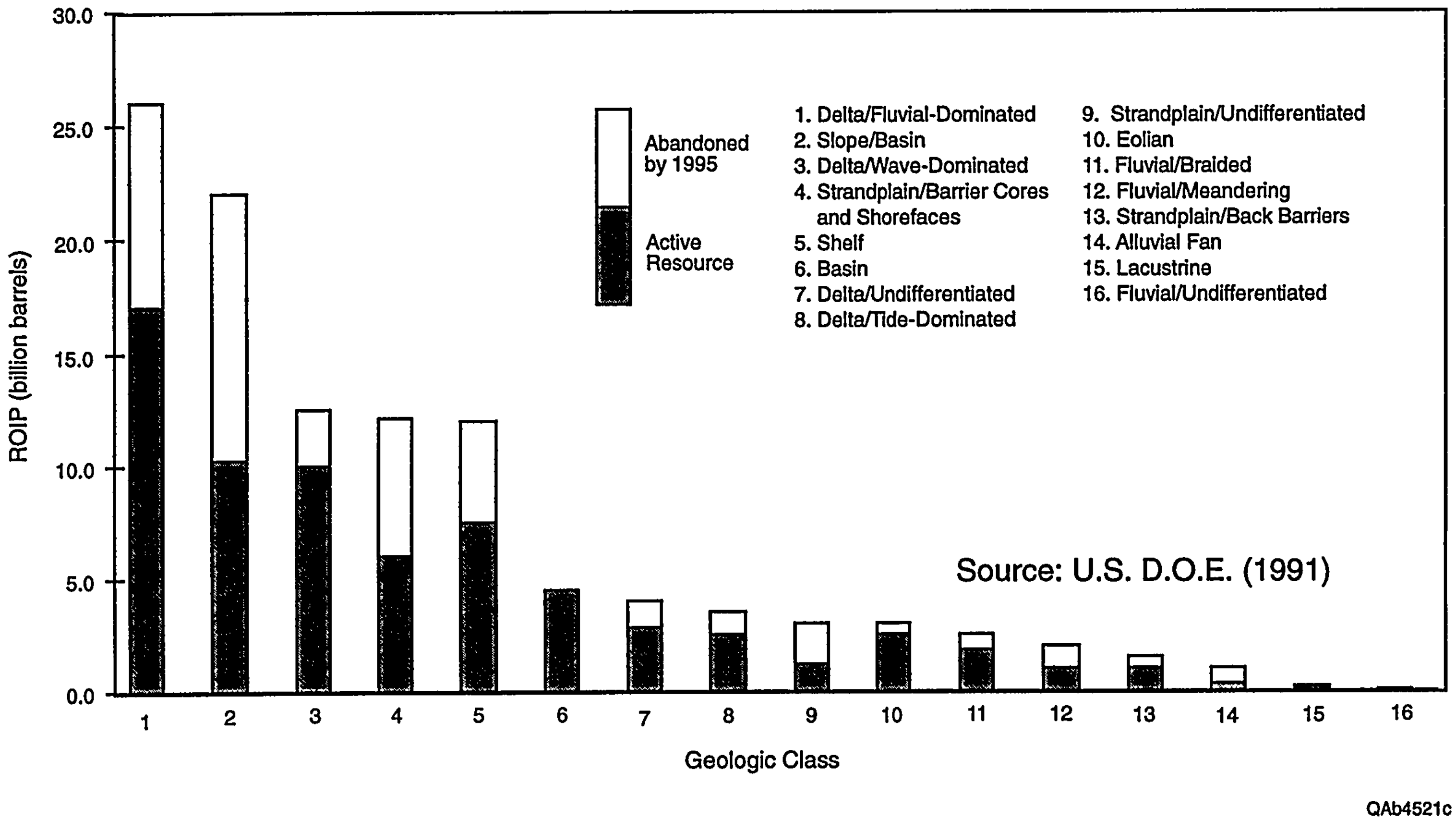


Figure 1. Histogram of remaining-oil-in-place and abandonment potential for U.S. clastic reservoirs, by depositional setting. In 1991, fluvial-dominated deltaic settings account for the greatest remaining resource, at over 25 billion barrels in place. A large percentage of this resource is threatened by premature reservoir abandonment. Once abandoned, any resources remaining are essentially lost forever because of the high cost of replacing producing infrastructure. Data from the U.S. Department of Energy (1991).

time and money for operators, some comments on criteria that can be used to select the most prospective reservoirs in a mature field for detailed study are given. Finally, our efforts to transfer this information to operators and encourage the application of this methodology to increase production are presented.

Importance of Integrated Characterization to U.S. Resource Base

Near-Term Domestic Oil Resources

Remaining domestic oil resources represent an important energy reserve for the United States. Because liquid hydrocarbons are expected to remain the principal source of energy for our society well into the coming century, and because secure inexpensive energy supplies are critical to economic growth, we must protect and husband our domestic oil resources. A large percentage of these resources reside in mature fields where production costs are inherently higher than newer fields because of greater water production and disposal costs. Under current management practices, in fact, many of these fields are nearing uneconomic status and may be abandoned, despite the fact that they contain large volumes of oil that, together, represent a critical domestic resource. Once they are abandoned, reestablishing access to these resources is rarely economically feasible because of the cost of reinstalling infrastructure. As a consequence, their loss is essentially permanent.

The U.S. DOE has recognized this danger and established a program to maintain access to these resources. This program fosters research into methods that can increase production from these fields in the near term, thus revitalizing their economic outlook and preventing premature abandonment. The DOE has divided remaining resources into classes on the basis of the original depositional setting of the reservoir rock and prioritized these classes by volume of remaining resource and threat of premature abandonment. Classification by depositional setting was done because the setting exerts a first-order control on the reservoir nature which, in turn, controls the factors that have prevented complete recovery of the resource.

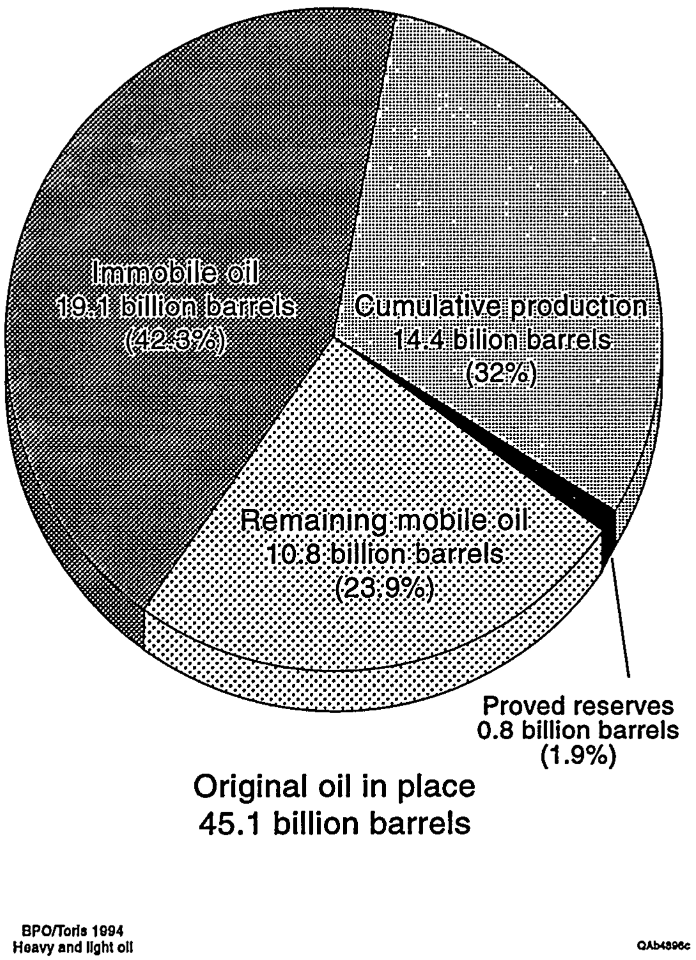


Figure 2. Distribution of original-oil-in-place in fluvial-dominated reservoirs. The volume of mobile oil remaining in these reservoirs, 10.8 billion barrels, is more than 10 times the current proved reserves and represents a resource nearly as significant to the United States as Prudhoe Bay field. Data from U.S. Department of Energy TORIS database (1994)(personal comm., Bartlesville Project Office, 1996).

In 1991, the DOE determined that reservoirs deposited in fluvial-dominated deltaic (FDD) settings (Class I) contained the highest priority resource. They represented the largest volume of remaining oil, more than 25 billion barrels (Bbbl), one-third of which was projected to be abandoned by 1995 (Figure 1). More recent estimates by the DOE were higher still. An analysis of the Tertiary Oil Recovery Information System (TORIS) in 1994 revealed that of 45 Bbbl originally in Class I reservoirs, more than 30 Bbbl remain. More than 19 Bbbl of the remaining oil are immobile (Figure 2) and unrecoverable by conventional low-cost primary or secondary recovery methods. That leaves nearly 11 Bbbl, roughly the size of the Prudhoe Bay discovery, still remaining to be targeted in the near term (Figure 2) by currently economic methods. This represents more than 40 percent of the mobile oil originally in the reservoirs, despite roughly five decades (on average) of production!

Causes of Unrecovered Mobile Oil in FDD Reservoirs

In the past, FDD reservoirs have commonly been developed with wells placed in geometric grids with predetermined spacing. Unfortunately, these reservoirs are not uniformly distributed or internally homogeneous. Instead, reservoir sandstone bodies occur in a range of shapes and sizes. Reservoirs can be separated into these bodies, or compartments, by laterally or vertically intervening shales and each compartment can be internally complex. For example, a sandstone reservoir body (compartment) deposited by a deltaic distributary channel can be narrow and elongated in the dip direction, and can contain many cross-cutting low permeability shale drapes (internal heterogeneities) that inhibit uniform flow of the oil from the reservoir toward the well bore. Consequently, wells drilled on a rigid grid may miss individual bodies in a particular reservoir interval, resulting in untapped compartments. Additionally, wells penetrating a reservoir body may be placed too far apart to efficiently drain it, leading to incompletely drained compartments. In FDD reservoirs, the most expedient way to increase production is to map reservoir compartments using geologic and geophysical information, evaluate their internal heterogeneity by applying engineering methods to production and test data, and identify untapped and incompletely drained compartments that can be targeted through recompletions of existing wells or the careful placement of infill wells. The following sections provide detail on the depositional controls on reservoir architecture and heterogeneity.

Stratigraphic Architecture and Scales of Reservoir Heterogeneity

The architecture of sandstones in clastic reservoirs has a direct impact on hydrocarbon recovery. Internal features within reservoir sandstone units define the geometry of fluid pathways that control the efficiency of hydrocarbon migration to the well bore and therefore provide fundamental constraints on the ultimate volume of conventionally recoverable oil and gas that remain in the ground when the reservoir is abandoned (Tyler and others, 1992). Understanding the details of reservoir architecture and its inherent control on fluid migration is critical to efficiently targeting the remaining recoverable oil resource in maturely developed reservoirs.

The internal geometry of sandstone bodies and the degree of interconnectedness, communication, or compartmentalization between individual reservoir sand bodies are products of the nonuniformity, or heterogeneity, of a rock reservoir (Alpay, 1972). Reservoir structure can be exceedingly complex, containing heterogeneities from scales of kilometers down to scales of less than 1 millimeter (Lasseter and others, 1986). To facilitate studies of the various types of heterogeneities present in rock reservoirs, researchers have arbitrarily divided reservoir heterogeneity into four different classes, or levels, that relate to different scales of investigation (Alpay, 1972; Weber, 1986; Tyler, 1988). These levels of heterogeneity range from the megascopic identification of variations in depositional style and sediment stacking patterns within an entire sedimentary basin sequence, to macroscopic and mesoscopic variations described within an individual depositional unit, to the microscopic study of pore throat variations between grains in a single core (Figure 3). The description and characterization of reservoir heterogeneity at each of these scales require separate methodologies, different data types, and the use of various analytical tools designed to measure and detect heterogeneity at different levels of resolution (Figure 4) (Worthington, 1991; Jackson and others, 1993).

Megascopic studies of reservoir heterogeneity address large-scale relationships between reservoirs that occur within a play trend or field area (basin scale and field scale) and are controlled by regional variations in base level that occur in response to changes in eustasy, sediment supply, subsidence, and climate (Miall, 1988). An understanding of regional-scale variations in reservoir architecture (for example, connected, laterally amalgamated fluvial channels versus isolated, vertically stacked fluvial channels) is important in identifying reservoir analogs within a play and assessing intrafield variations in reservoir quality and recovery efficiency.

Intermediate scales of reservoir heterogeneity include variations at the macroscopic level of the genetic sand unit or depositional facies (for example, point-bar versus crevasse splay deposits) and mesoscale variations within ripple laminae and beds. Microscopic heterogeneity refers to variations at the scale of grains, pores, and pore throats. These small-scale heterogeneities are responsible for variations in capillarity and local fluid-flow pathways that control the nature of oil

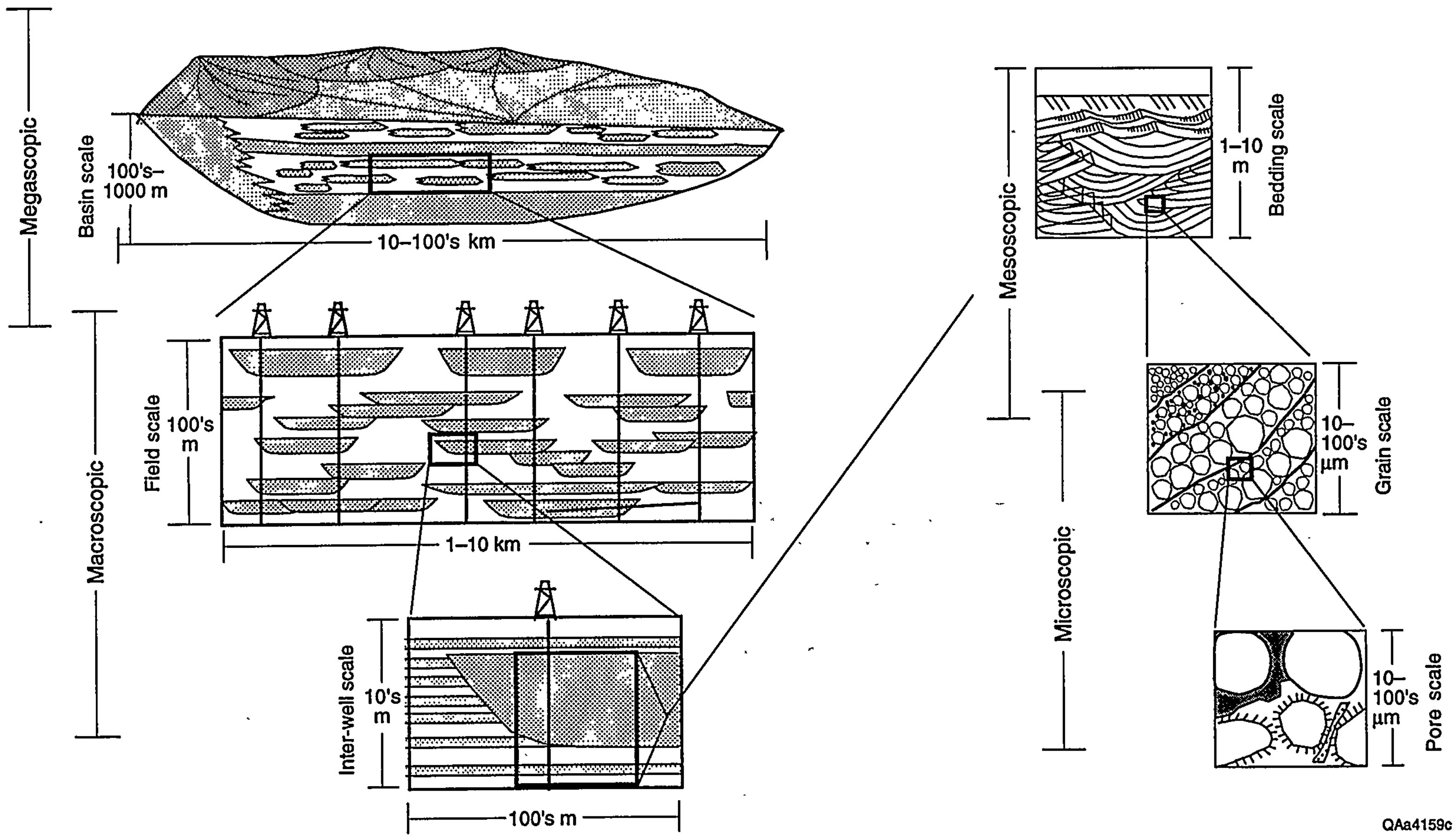


Figure 3. Examples of scales associated with the various levels of heterogeneity present in fluvial-deltaic reservoirs. Compiled from Weber (1986) and Miall (1988).

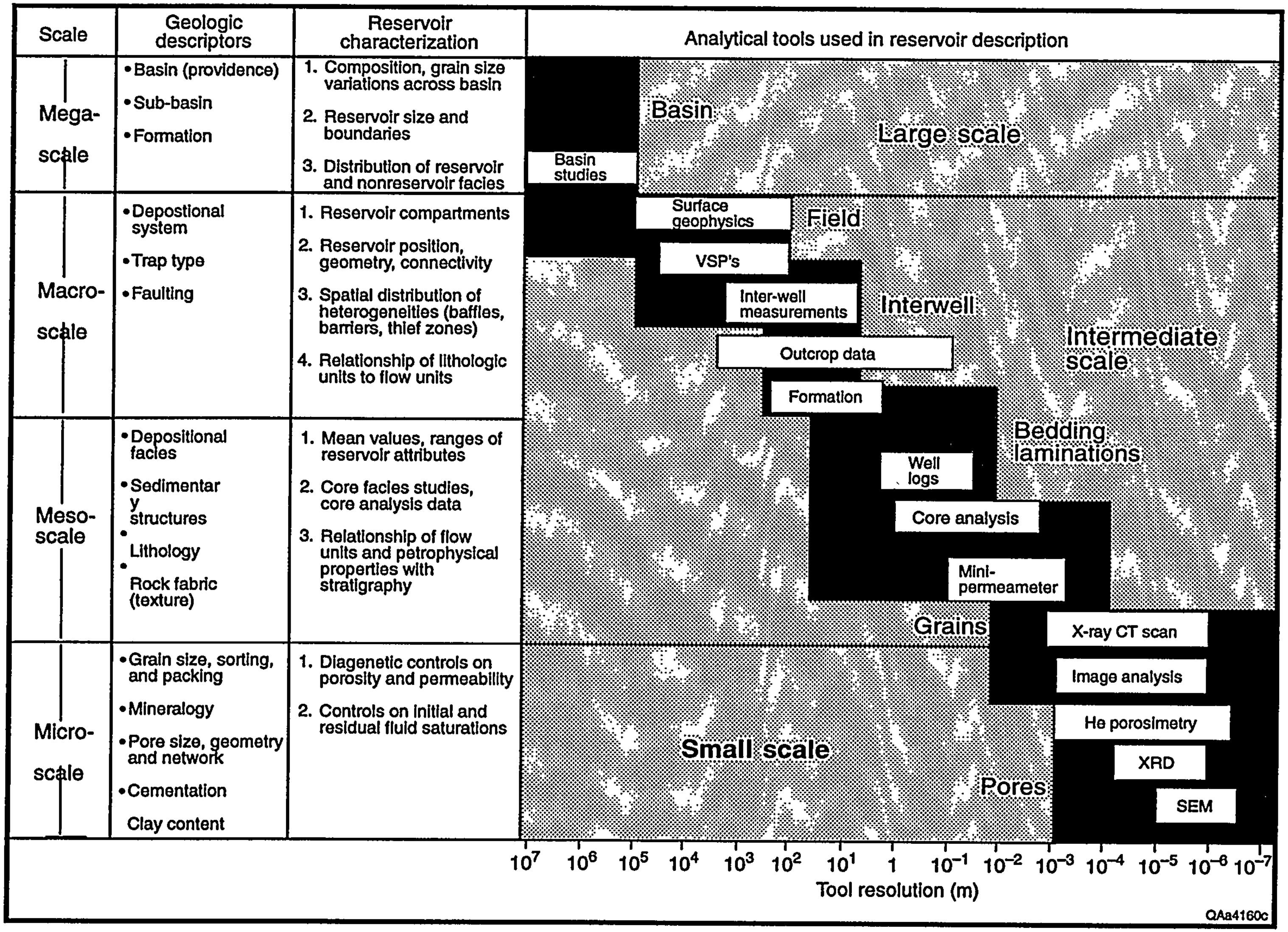


Figure 4. Analytical tools used in the description of reservoir heterogeneity at various scales. Data from Worthington (1991) and Jackson and others (1993).

saturation and the retention of residual oil in the vicinity of the well bore. This level of heterogeneity is largely a function of diagenetic processes.

Heterogeneity in fluvial sandstones has also been described in terms of a hierarchy of bounding surfaces of various scales (Miall, 1988). These range from large-scale sixth-order surfaces that separate depositional sequences; to fifth- and fourth-order surfaces defining major reservoir packages and individual channel units at the interwell level, respectively; to smaller fourth- through first-order bounding surfaces, which are small-scale features recognized at the core level, but their limited lateral extent (<25 acres) precludes correlation at the interwell level. A summary of the various scales and nomenclature associated with reservoir heterogeneity is provided in Table 1.

Compartmentalization in Fluvial-Deltaic Reservoirs

The scale of heterogeneity that is most critical in controlling fluid-flow pathways and is the key to accessing unrecovered mobile oil remaining in the reservoir is the intermediate, interwell, or macroscopic scale of heterogeneity. This level of heterogeneity most closely corresponds to the reservoir flow unit. Macroscopic features include variations in depositional and diagenetic facies that serve to compartmentalize a reservoir. Physical bounding elements that define the permeability structure of a reservoir and divide it into separate flow units include both bedding surfaces as well as nonpermeable rock types that act as intrareservoir seals between individual reservoir compartments (Tyler and Finley, 1991). The types of permeability barriers present and the style and extent of reservoir compartmentalization that they create are directly related to the depositional system. LeBlanc (1977) documented many examples of how the distribution, internal characteristics, and continuity of sandstone reservoirs are primarily controlled by the original environment of deposition.

Stratigraphic compartmentalization that is inherent in fluvial-deltaic depositional systems is responsible for the incomplete and inefficient recovery of available oil and gas resources within a developing field. Various categories of infield reservoir compartments, in addition to those

Table 1. Scales of reservoir heterogeneity.

Level of Heterogeneity and Order of Bounding Surface (Miall, 1988)	Lateral Dimensions (Width)	Vertical Dimensions (Thickness)	Depositional Unit	Subsurface Correlation (Data Types and Mapping Methods)
Basin Scale *(6th order)*	10-100's km	100's-1000's m	• Formation • Member	• Regional correlation of wireline logs
Field Scale *(5th order)*	1-10 km	100's m	• Channel (Sheet) sandstones • Channel (Ribbon) sandstones	• Intrafield correlation of wireline logs • 2-D seismic data • Closely spaced logs • 3-D seismic data
Interwell (Intrafield) Scale *(4th, 3rd, 2nd orders)*	100's m	10's m	• Macroforms • Bed cosets	• Core studies, facies analysis
Bedding Scale *(1st order)*		1-10 m	• Individual crossbeds	• Core studies
Grain Scale		10-100's mm		• Petrography
Pore Scale		10-100's mm		• Petrography • SEM • X-ray diffraction • Capillary pressure measurements

currently producing or depleted, are recognized as targets for incremental recovery in mature fields (Levey and others, 1992). These include (1) untapped reservoir compartments, (2) incompletely drained reservoir compartments, and (3) deeper pool targets. Characteristics of these various reservoir targets have been summarized in Table 2. Untapped and incompletely drained compartments are the primary targets that can be identified through detailed depositional facies analysis and the identification of interwell scale heterogeneities that divide reservoir facies into separate flow units. Lithologic heterogeneity and the presence of uncontacted and incompletely drained reservoir compartments located between existing well spacing are illustrated in Figure 5. The present level of development within a field, described by current well spacing and the density of completions within reservoir zones, can be used as a relative indicator of remaining untapped potential.

In addition to untapped and incompletely drained reservoir targets, there may be additional resource potential present in deeper pool reservoirs, which may exist in reservoir zones already penetrated, but below previously established production. Evaluations of deeper-pool targets are based on a much less dense framework of data; therefore, they often require regional facies analysis and sequence stratigraphic studies of reservoir systems to properly assess their recovery potential.

Recovery Potential of Fluvial-Deltaic Sandstone Reservoirs

Estimates of oil recovery from reservoirs in fields across the United States average 34 percent (Tyler, 1988). A recent survey of more than 450 Texas oil reservoirs documented a well-defined trend of declining recovery efficiency with increasing heterogeneity and complexity of reservoir architecture (Galloway and others, 1983). Recovery efficiencies in clastic reservoirs range from a high of nearly 80 percent in the architecturally simple, laterally continuous, wave-dominated delta and barrier-strandplain reservoirs of East Texas, to a low of 8 percent in sandstone-poor, discontinuous basin-floor turbidite reservoirs in the Permian Basin (Tyler and others, 1984). Fluvial-deltaic reservoirs fall between these extremes, with complex channelization and abrupt

Table 2. Reservoir compartment terminology.

TYPE	DEFINITION	STRATEGIES FOR IDENTIFICATION
1. UNTAPPED RESERVOIRS	• Not contacted during original field development • Separated vertically or laterally from adjacent producing reservoirs	• Identification by stratigraphic correlation of key shale horizons • Small and narrow channels within a single operational reservoir unit exhibit high degree of variability
2. INCOMPLETELY DRAINED RESERVOIRS	• Not drained when original completions reach an economic limit • May or may not be separated vertically or laterally from adjacent reservoirs	• Correlation of marker horizons within reservoir aids in recognition of separate compartments • Pressure data can be used to identify barriers which inhibit complete drainage of a reservoir
3. DEEPER POOL RESERVOIR	• May have been contacted during original field development, but is at depth below established production	• Regional facies analysis • Development of sequence stratigraphic framework for reservoir systems • Application of field analogs

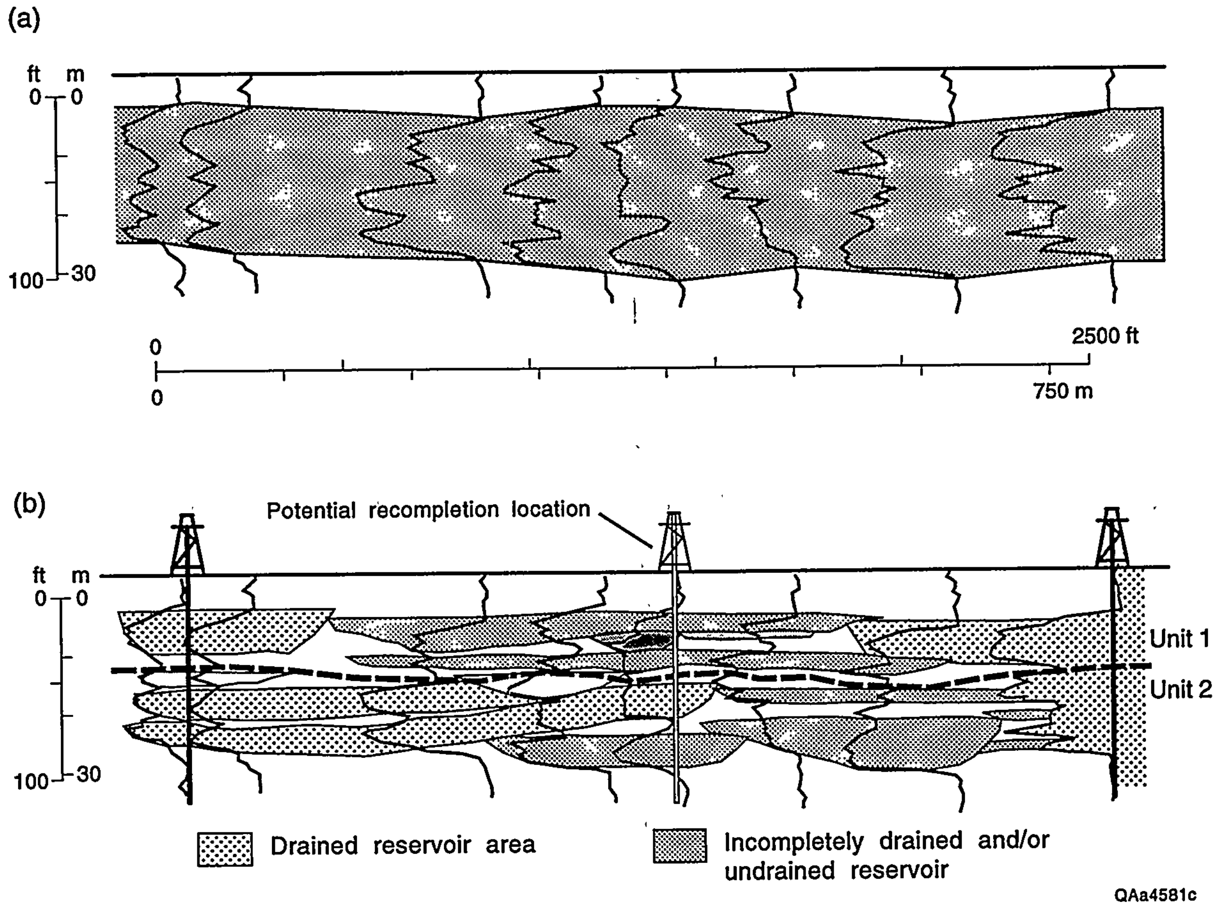


Figure 5. Schematic geologic cross section contrasting the generalized interpretation of a sandstone reservoir as a simple, laterally continuous (homogeneous) producing zone (a) with a more detailed interpretation of the same sandstone unit as a complex heterogeneous zone consisting of multiple reservoir compartments (b). In the traditional example of the simple reservoir unit (a), good reservoir continuity suggests that the reservoir can be completely drained at the current well spacing. The complex architecture illustrated in (b) suggests the presence of facies boundaries within the sandstone that create multiple compartments, some of which are only partially drained or are completely untapped at the present well spacing. Modified from Jackson and Ambrose (1989).

facies variation in some fluvial-deltaic reservoir systems responsible for recovery efficiencies as low as 20 percent. This large variation in recovery efficiency is well illustrated for Texas oil reservoirs, because populations of fluvial-deltaic, deltaic, and submarine fan reservoirs contain similar volumes of oil in place but the deltaic reservoirs account for more than 50 percent of total reservoir production (Tyler and Finley, 1991).

Lateral and vertical reservoir heterogeneity is controlled by the depositional process responsible for creating the reservoir, and this heterogeneity in turn is responsible for developing the reservoir architecture that provides the fundamental control on hydrocarbon recovery efficiency in a given reservoir unit (Tyler and Finley, 1991). Developing a detailed understanding of the processes, styles, and scales of heterogeneity that characterize a particular reservoir type can become a powerful predictive tool in the identification and delineation of additional unrecovered oil and gas resources. Using this approach, major sandstone types can be classified according to their degree of vertical and lateral heterogeneity and this classification can be used to predict recovery efficiencies and the residency of unrecovered mobile oil in the reservoir (Tyler and Finley, 1991) (Table 3).

Project Objectives and Approach

The primary objective of this project has been to develop and demonstrate advanced, integrated, multidisciplinary reservoir characterization methods that allow identification of untapped and incompletely drained compartments (Table 4), which can then be targeted for near-term recovery methods. These actions will increase production from mature fluvial-deltaic reservoirs, revitalizing mature fields and maintaining access to this class of reservoirs, thereby preventing the loss of important domestic energy resources.

To achieve our primary objective, we have integrated geological facies models with geophysical, petrophysical, and engineering data to develop an advanced, integrated characterization methodology. We have applied this methodology to selected fields and reservoirs to provide specific examples of near-term recovery opportunities (Table 4).

Our approach has been to select a trend of mature fluvial-deltaic reservoirs in danger of abandonment, assemble an overview of reservoir characteristics, select fields and reservoirs for characterization, and identify untapped and incompletely drained compartments (Table 4). We selected a prolific mature fluvial-deltaic oil play on the Texas Gulf Coast as a laboratory for the development and demonstration of characterization techniques and selected reservoirs in two

Table 3. Spectrum of reservoir heterogeneity and resulting recovery potential in clastic reservoirs (adapted from Tyler and Finley, 1991).

LATERAL HETEROGENEITY	**LOW**		**MODERATE**	**HIGH**	
VERTICAL HETEROGENEITY	***Depositional Environment***	***Recovery Potential***	***Depositional Environment***	***Depositional Environment***	***Recovery Potential***
LOW	Wave-dominated delta Barrier core Barrier shoreface Sand-rich strandplain	Very high recovery efficiency	Delta-front mouth bar Proximal delta front Tidal deposits Mud-rich strandplain	Meander belt *(single story)* Fluvial-dominated delta *(single story)* Back barrier *(single story)*	Low recovery efficiency Mobile oil compartmentalized, uncontacted, and laterally bypassed
MODERATE	Eolian Wave-modified delta (distal)		Shelf bars Alluvial fan Fan delta Lacustrine delta Wave-modified delta (proximal)	Braided stream Tide-dominated delta	
HIGH	Basin-floor turbidites	Low recovery efficiency Mobile oil vertically bypassed		Back barrier *(stacked units)* Fluvial-dominated delta *(stacked units)* Fine-grained meander belts *(stacked units)* Submarine fans *(stacked units)*	Very low recovery efficiency Mobile oil uncontacted and bypassed

Table 4. Summary of project objectives.

OBJECTIVE	APPROACH
1. Demonstrate the application of state-of-the-art reservoir characterization to assess the reserve growth potential in mature fluvial/deltaic oil fields of South Texas	• Utilize maturely developed fluvial and deltaic sandstone reservoirs as a laboratory for reservoir characterization techniques
2. Integrate geological facies models with petrophysical and engineering data to characterize fluvial-deltaic reservoir heterogeneity and identify controls on the location and volume of unrecovered mobile and residual oil	• Categorize engineering information by depositional and diagenetic characteristics
3. Provide examples from selected fields and reservoirs to serve as a guide for other fields and reservoirs	• Characterize major Frio reservoirs in the Vicksburg Fault Zone oil play in the Texas Gulf Coast Basin
4. Define near-term reserve growth potential in selected fields by describing the spatial distribution of remaining oil resource	• Emphasize practical field-oriented techniques to screen for reserve growth potential and develop approaches to direct strategic targeting of new infill drilling and recompletions to overcome reservoir compartmentalization

fields for detailed study. Whereas successful demonstration of these techniques will most tangibly influence production in Texas fluvial-deltaic trends, presentation of findings to national audiences will also contribute to increased production throughout the United States.

The trend selected, the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) play of South Texas, has already produced nearly 1 Bbbl of oil since discovery and development in the 1930's and 1940's but still contains 1.6 Bbbl of unrecovered mobile oil. More than half of the reservoirs have already been abandoned, and thus large volumes of oil may remain unproduced unless advanced characterization techniques are applied to define untapped, incompletely drained, and new pool reservoirs as suitable targets for near-term recovery methods.

This project has developed interwell-scale geological facies models of the Frio fluvial-deltaic reservoirs and combined them with engineering assessments to characterize reservoir architecture and fluid-unit boundaries and to determine the controls that these characteristics exert on the location and volume of unrecovered mobile oil and residual oil. These studies have lead directly to the identification of specific opportunities to exploit these heterogeneous reservoirs for incremental recovery by recompletion and strategic infill drilling.

Project Description

This project was divided into three major phases (Figure 6). The first phase included (1) the initial task of screening fields within the play to select representative reservoirs that have a large remaining oil resource and are in danger of premature abandonment (task 1), and (2) performing initial characterization studies on these reservoirs in order to identify the potential for untapped, incompletely drained, and new pool reservoirs (tasks 2–4). The second phase involved advanced characterization of the selected reservoirs in order to delineate incremental resource opportunities. This included volumetric assessments of untapped and incompletely drained oil, along with an analysis, by reservoir, of specific targets for recompletion and targeted infill drilling. The third and final phase of the project consisted of a series of tasks associated with final project documentation, technology transfer, and the extrapolation of specific results from reservoirs in this study to other heterogeneous fluvial-deltaic reservoirs within and beyond the Frio play in South Texas.

Specific accomplishments throughout the project are presented in each annual report (McRae and others, 1994, 1995, and Holtz and others, 1996). Tables 5 through 7 provide summaries of these activities. Activities that postdate the last annual report consist predominantly of technology transfer events, and are summarized in that major section.

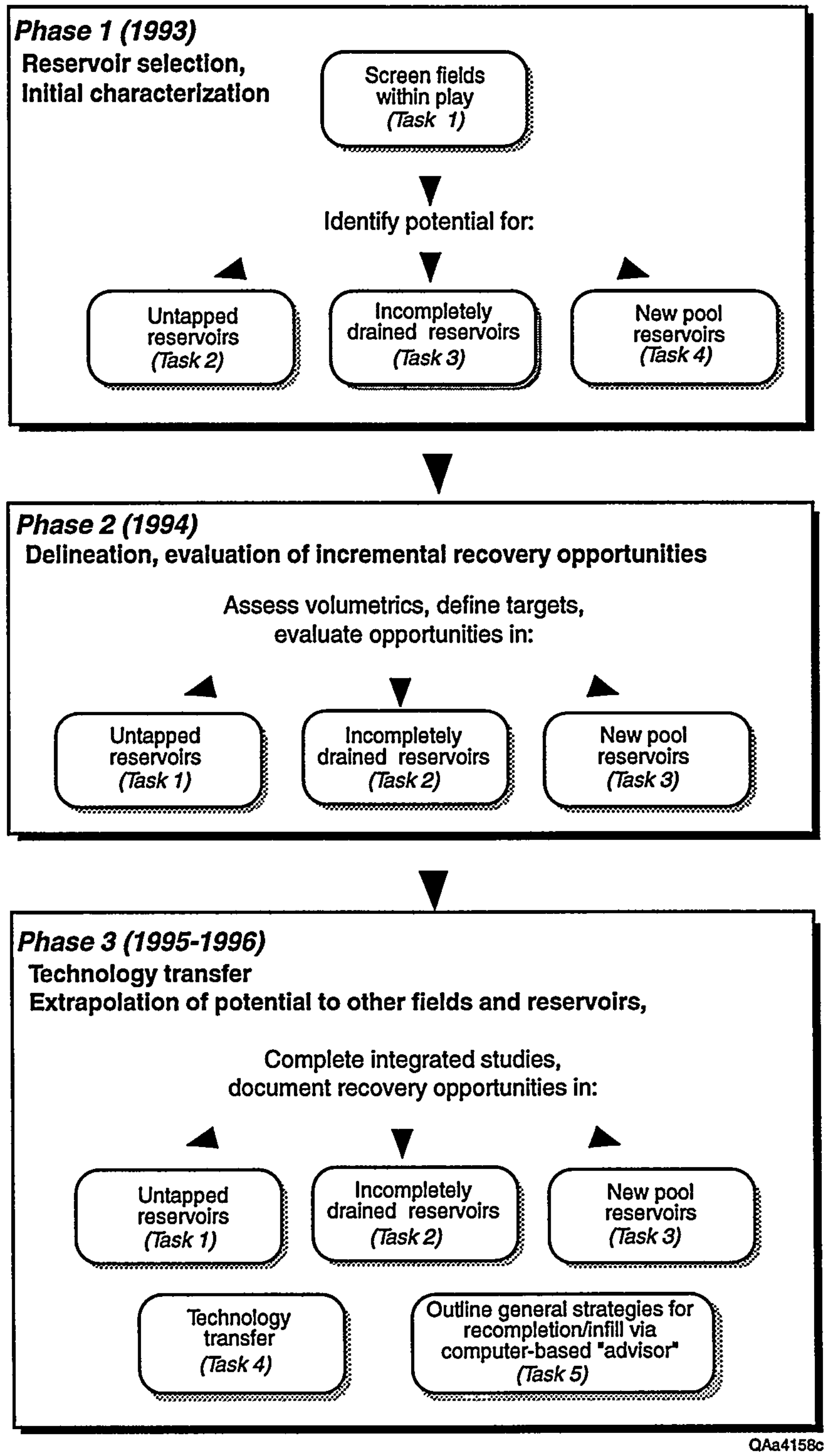


Figure 6. Diagram of work structure for this project illustrating three primary phases and a breakdown of individual tasks associated with each phase of the project.

Table 5. Significant accomplishments in Project Year 1: 1992–1993.

1. Selection of two South Texas fields for reservoir characterization studies
2. Reviews with field operators, data gathering and inventory
3. Development of digital log data bases
4. Construction of type logs for fields, establishment of regional cross-section framework
5. Preliminary synthesis of reservoir log, core, and production data
6. Synthesis of reservoir pressure and production data
7. Comparison of production histories by reservoir
8. Synthesis of core analysis data by reservoir

Table 6. Significant accomplishments in Project Year 2: 1993–1994.

1. Statistical analysis of petrophysical attributes for middle Frio (fluvial), lower Frio (fluvial-deltaic), and Vicksburg (deltaic) stratigraphic subintervals within the entire play.
2. Playwide evaluation of additional resource potential and assessment of remaining mobile oil in middle Frio fluvial, lower Frio fluvial-deltaic, and Vicksburg deltaic sandstone reservoirs.
3. Completion of regional stratigraphic framework in Rincon and T-C-B fields and documentation of general reservoir architectural styles.
4. Selection of two representative reservoirs in each field for detailed study.
5. Digitized log data for nearly 200 wells in Rincon field were depth adjusted, normalized, and flagged with associated production data, stratigraphic tops, log facies type, net sandstone thickness, percentage sandstone, wireline core porosity and permeability, vertical log facies type, and lateral depositional facies type interpreted from facies maps.
6. Log data from more than 50 wells in T-C-B field were digitized for petrophysical analysis and annotated with associated production data and stratigraphic tops.
7. Maps illustrating distribution of oil production, initial potential, log facies, net sandstone thickness, percentage sand, and permeability-thickness have been generated for 8 separate reservoir subunits in Rincon field and compared to identify differences in sandstone depositional styles and production behavior and identify zones with high potential for containing unproduced oil.
8. Stratigraphic cross sections were constructed to document subregional stratigraphic framework of reservoirs in greater T-C-B field area, identify stratigraphic hierarchy and sandstone architectural styles within field study area, and aid in the selection of specific reservoir zones for detailed study.

Table 7. Significant accomplishments in Project Year 3: 1994–1995.

1. Routine core analysis data from 100 wells in Rincon field were categorized by depositional facies, resulting in more accurate facies-based porosity-permeability relationships and correct apportioning of commingled production to each reservoir zone.
2. Special core analysis data were measured in 15 samples from Rincon reservoirs to improve calculations of original oil in place, residual oil saturation, and irreducible water saturation, resulting in a more accurate evaluation of remaining reserves.
3. A petrographic study of 22 samples from Rincon reservoirs was carried out to determine the effect of diagenesis on reservoir quality and to supplement results of the special core testing.
4. Detailed characterization of two upper delta plain fluvial reservoirs in T-C-B field was completed, resulting in the identification of 17 recompletion and 19 infill drilling opportunities.
5. An accommodation-based model was developed that improves the prediction of reservoir architecture and between-well heterogeneity and establishes a method for ranking reservoirs in terms of reserve-growth potential on a quick-look basis.
6. Geologic societies in two cities have offered to host short courses scheduled for early 1996, and work has begun on a set of course notes for attendees.
7. Methodology and results of this study have been transferred to industry in 5 technical presentations, 4 publications, and 2 related Bureau short courses.
8. Objectives and a tentative structure for a microcomputer-based geological advisor have been established, and programming of a test version has begun.

PLAYWIDE RESERVOIR STUDIES

M.H. Holtz and L.E. McRae

Overview

A geologic and engineering review of playwide characteristics was carried out to provide a summary of basic regional information to operators and to evaluate the volumes of resources remaining to be recovered by operators. The following section provides a review of production history and geologic setting, an evaluation of playwide engineering parameters and the resource estimates calculated from them, and a breakdown of engineering parameters and resources by stratigraphic interval.

Location and Characteristics of Fields within the Play

The Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) play (Figure 7) is located in South Texas and extends from Starr County northeastward to Jim Wells and Nueces Counties, Texas (Galloway and others, 1983). Fields in the play produce oil from heterogeneous fluvial and deltaic sandstones of the Oligocene Frio and upper Vicksburg Formations on the eastern, downthrown side of the Vicksburg Fault Zone. Oil-bearing traps consist predominantly of shallow rollover anticlines that formed during later stages of fault movement along the fault zone (Jackson and Galloway, 1984; Tyler and Ewing, 1986). Deeper structures are characterized by synthetic and antithetic faults with large displacements commonly in excess of hundreds of feet. Individual fields within the play produce from a stratigraphic interval that averages 2,000 ft in thickness and consists of 20 to 40 separate sandstone reservoirs that are interbedded with mudstone (Stanley, 1970).

Production History

The Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) has produced nearly 1 Bbbl of oil equivalent from 129 reservoirs in fields throughout the play in South Texas (Galloway and others,

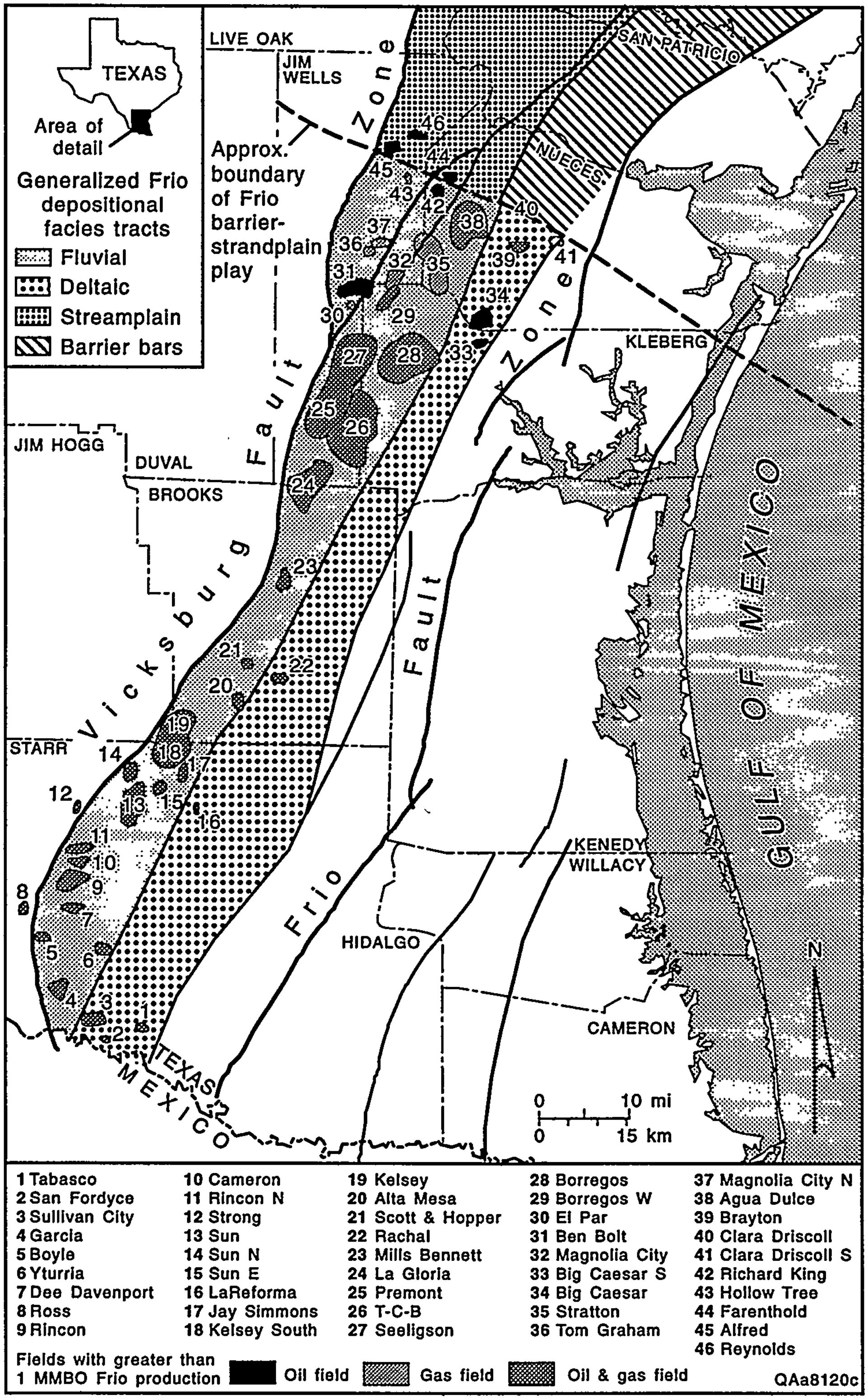


Figure 7. Location map of major oil and gas fields in the Frio Fluvial-Deltaic Sandstone Play in South Texas. Reservoirs from these fields have been subdivided according to stratigraphic position and depositional facies into middle Frio (fluvial) reservoirs and lower Frio (fluvial-deltaic) reservoirs to identify differences in heterogeneity style and better estimate remaining oil potential in each type of reservoir facies.

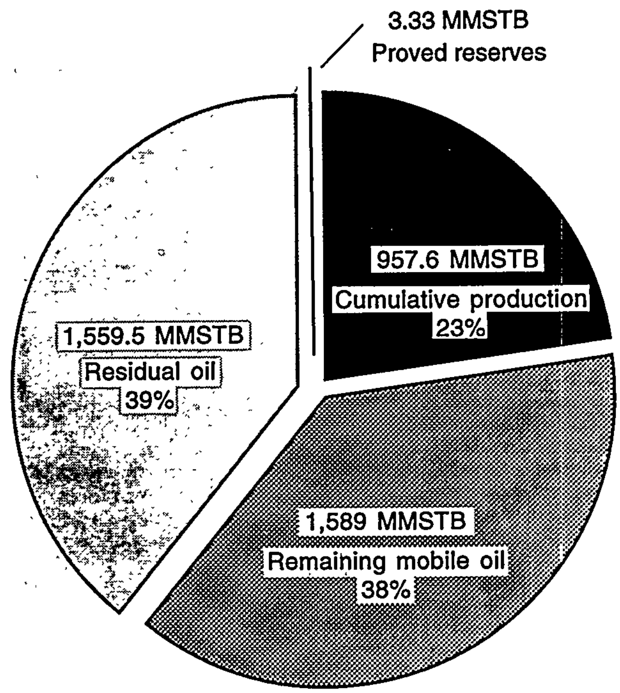


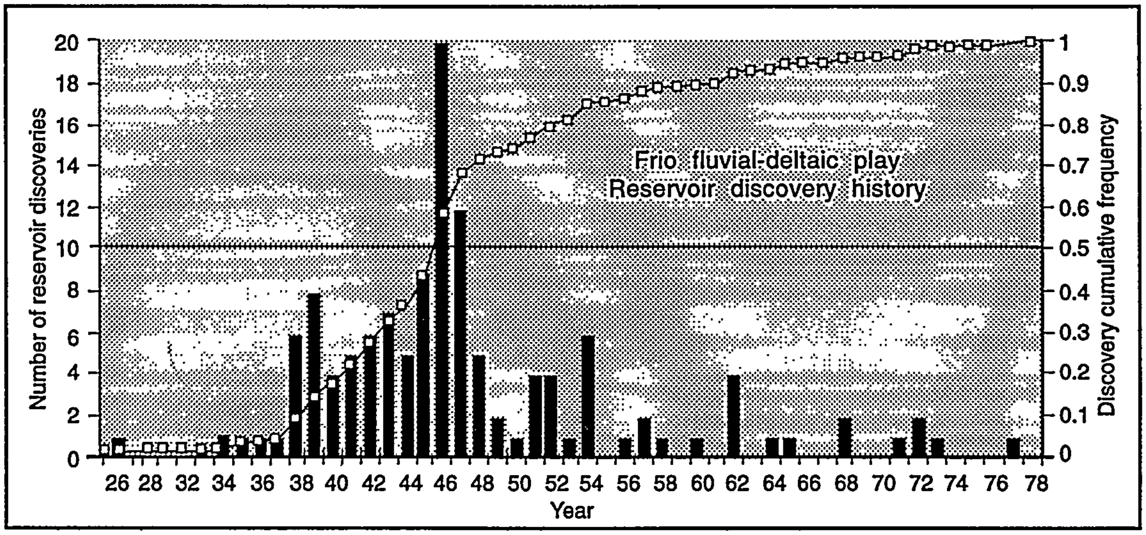
Figure 8. Distribution of the oil resources within reservoirs of the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) play in South Texas. Nearly 1 Bbbl have been recovered in more than four decades of production, but nearly two-thirds of the estimated original oil in place remain.

1983; Kosters and others, 1989). Total original oil in place estimates, however, are in excess of 4 Bbbl, of which 1.6 Bbbl is classified as unrecovered mobile oil, and nearly the same amount is attributed to residual oil resources (Figure 8).

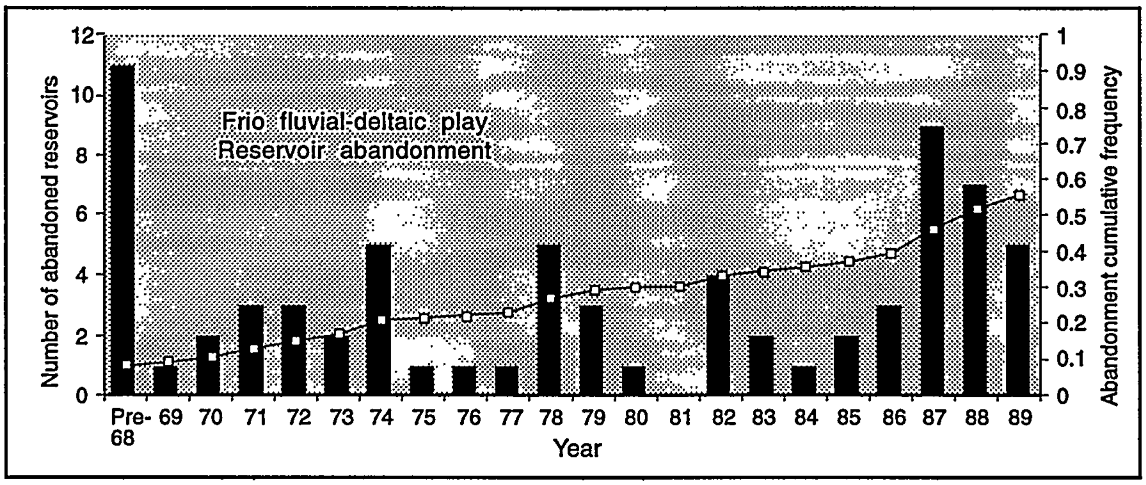
The development status of the play is classified as mature to supermature, because most of the major fields in the play were discovered in the late 1930's and early 1940's (Figure 9a). Reservoir abandonment rates increased significantly during the time period from 1987 to 1989 (Figure 9b). The number of producing wells in the play showed a precipitous decline of over 50 percent during a 5-yr period from 1974 to 1978. The play has been experiencing a steady decline in both overall production and individual flow rates throughout the 1980's (Figure 9c). By 1989, over one-half of the 129 reservoirs included in the play were no longer producing. Annual production from 376 active wells in 1989 was approximately 1.2 MMbbl. Average daily production rates from these wells had declined to 8.9 bbl/d.

Oil and natural gas reservoirs produce from the same stratigraphic interval. Production drive mechanism is dominantly gas-cap expansion. Most fields have large gas caps and have been unitized to properly develop and maintain pressure in these complex sandstone reservoirs. In

(a)



(b)



(c)

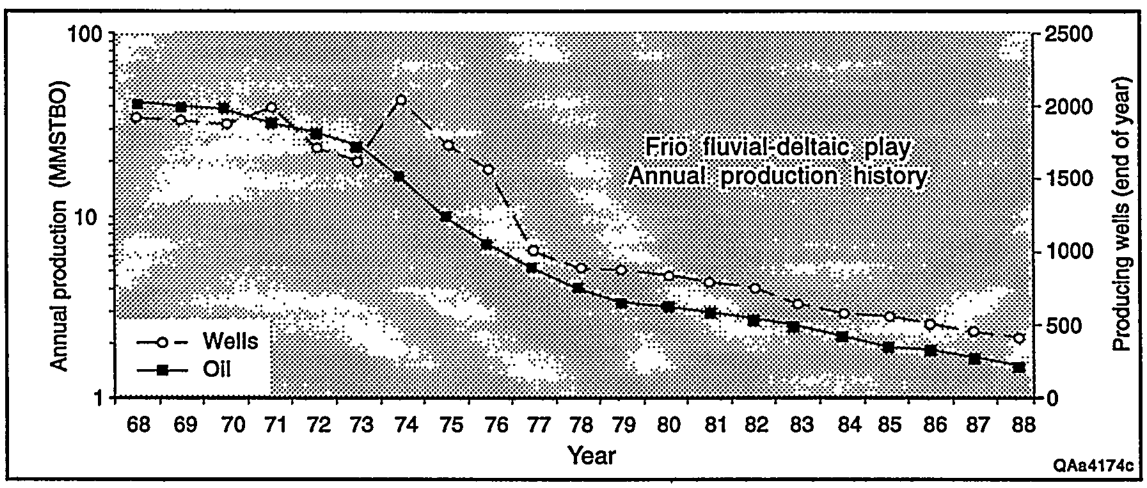


Figure 9. Histograms illustrating trends in reservoir discovery (A), reservoir abandonment (B), and decline in annual production (C) in the Frio Fluvial-Deltaic sandstone oil play. Oil production in the play has steadily declined since 1968, and as of 1991, nearly 60 percent of all producing reservoirs had been abandoned.

many cases, produced natural gas has been cycled back into some of the reservoirs to maintain production of oil.

Engineering attributes for Frio reservoirs are described in a later section. The typical reservoir is a dip-oriented fluvial or distributary-channel sandstone draped over a northeast-trending anticlinal structure. Individual sandstone reservoirs range from 10 to 50 ft in thickness and consist of individual or multiple amalgamated sandstone bodies. Porosity and permeability values average 25 percent and 430 md, respectively, and the average API gravity of produced oil is 41°. Reservoirs are internally compartmentalized by permeability baffles and barriers caused by mud-filled channel plugs, by rip-up-clast zones located between channel-on-channel contacts, and by more laterally extensive floodplain mudstone facies located in interchannel areas.

Regional Structural and Stratigraphic Setting

The entire Frio Formation in Texas has been divided into 10 plays based on regional variations in structure and depositional setting (Kosters and others, 1989). Fields in the play known as the Frio Fluvial-Deltaic Sandstone Play produce oil and gas from the eastern, downthrown side of the Vicksburg Fault Zone, a major down-to-the-coast listric normal growth fault system that parallels the Gulf coastline for over 100 mi (Figure 7). Faulting mainly offsets the Vicksburg Formation but also affects the lower portions of the overlying Frio Formation. Oil-bearing traps consist predominantly of shallow rollover anticlines that formed during later stages of movement along the fault zone (Stanley, 1970; Tyler and Ewing, 1986). Deeper structures within Vicksburg strata are characterized by synthetic and antithetic faults with large displacements commonly in excess of hundreds of feet.

Oil and gas reservoirs in this play occur within a 2,000-ft stratigraphic interval in fluvial-deltaic sandstones primarily of the Oligocene Frio Formation (Figure 10). The Frio Formation is part of a sedimentary wedge that records a major depositional offlap episode of the northwestern shelf of the Gulf of Mexico Basin (Figure 11). Frio sediments in South Texas represent the entry of a major extrabasinal river into the Gulf basin along the axis of the Rio Grande Embayment in

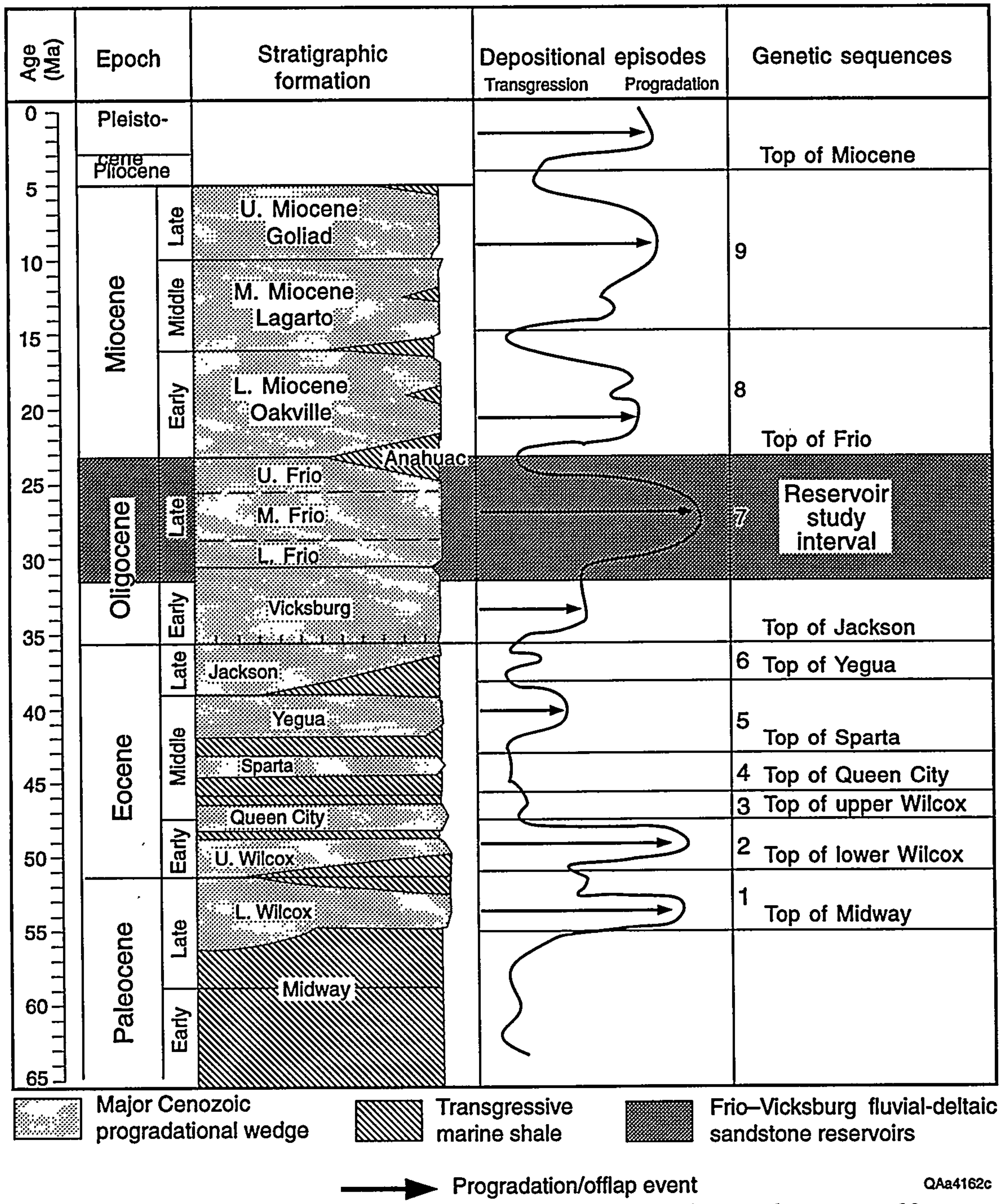


Figure 10. Stratigraphic column of Cenozoic sediments of the South Texas Gulf Coast. The sedimentary succession has been divided into a series of large-scale depositional episodes that represent major periods of progradation that occurred throughout the Cenozoic (Galloway, 1989b). Reservoirs in the Frio Fluvial/Deltaic Sandstone play are part of a larger Frio-Vicksburg genetic sequence.

Oligocene time. This ancient fluvial-deltaic complex has been divided into the Gueydan fluvial and Norias delta systems (Galloway and others, 1982). Fields within the Frio Fluvial-Deltaic Sandstone play occupy a transitional area between these two depositional systems (Figure 12). In

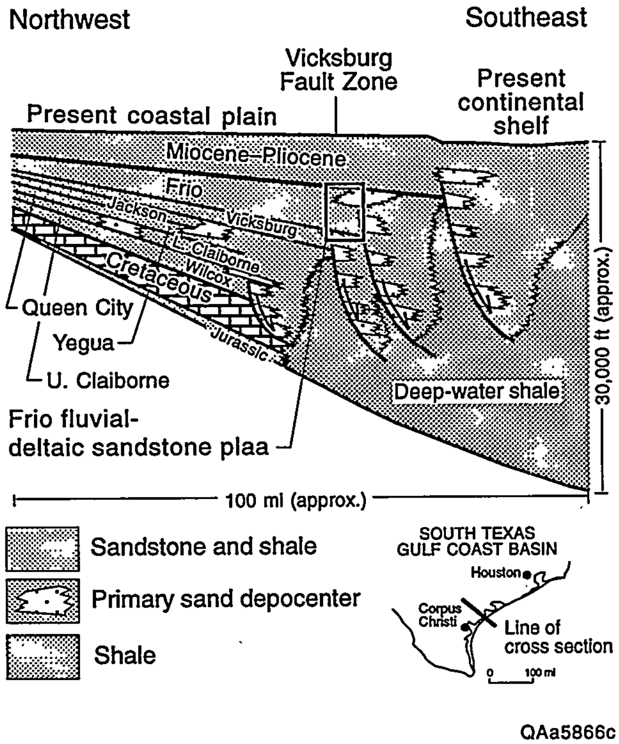
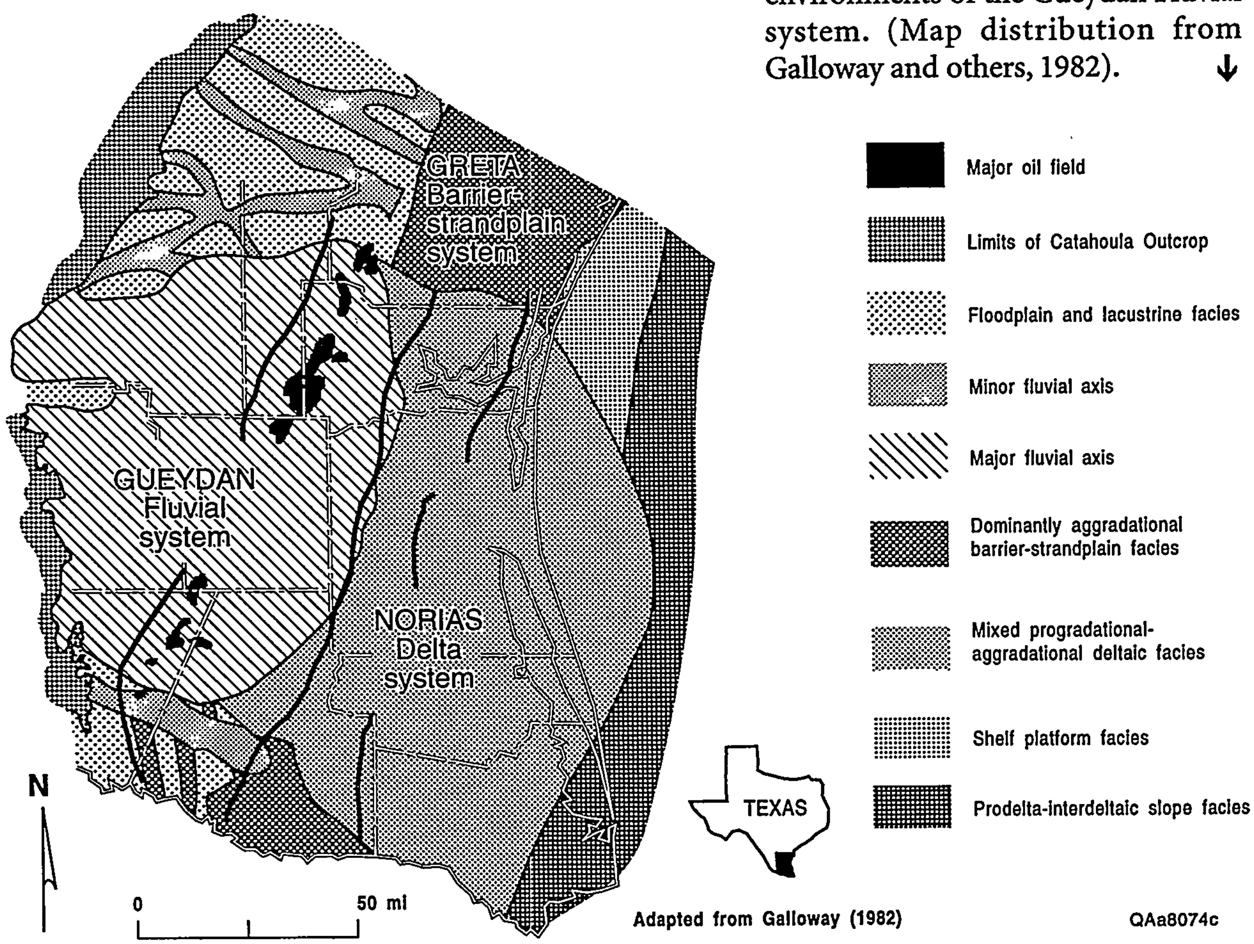


Figure 11. Schematic cross section of the South Texas Gulf Coast Basin. Modified from Bebout and others (1982).

Figure 12. General distribution of the Norias delta and Gueydan fluvial depositional systems responsible for deposition of the Frio stratigraphic unit. The Frio sediments in the vicinity of the Vicksburg Fault Zone were primarily deposited in moderate to high sinuosity mixed-load stream environments of the Gueydan Fluvial system. (Map distribution from Galloway and others, 1982). ↓



general, lower Frio sandstones represent deltaic facies of the ancestral Norias delta system, and middle and upper Frio sandstones predominantly reflect deposition in fluvial channels of the Gueydan fluvial system (Galloway and others, 1982). Important oil reservoirs in this sequence occur within progradational, fluvial-dominated deltaic depositional facies within the upper Vicksburg and lower Frio intervals and in aggradational fluvial facies in the middle Frio section (Figure 13).

Upper Vicksburg-Frio Genetic Sequence

The productive stratigraphic interval in the Frio Fluvial-Deltaic Sandstone Play is part of a larger genetic depositional sequence that reflects a series of depositional events that include strata from both Vicksburg and Frio Formations (Galloway, 1989b). These depositional events produce an overall genetic stratigraphic stacking pattern that consists of episodes of seaward-stepping deltaic progradation, vertically stacked fluvial aggradation, and landward-stepping retrogradation followed by a transgressive event (Figure 14). Reservoir sandstones within stratigraphic intervals exhibiting each sediment stacking style possess distinctive characteristics that control their producibility, determine their potential for incremental recovery, and dictate which strategies should be used to best identify locations of remaining mobile oil in undeveloped compartments (McRae and Holtz, 1994).

Sediment and rocks of the upper Vicksburg Formation represent the initial progradational phase of the Vicksburg-Frio genetic stratigraphic interval (Coleman and Galloway, 1991; Xue and Galloway, 1991). Vicksburg deposition in South Texas was strongly influenced during the development of the Vicksburg Fault Zone (Coleman, 1993; Coleman and Galloway, 1991). As a result, reservoir compartmentalization is controlled to a large degree by faulting, and stratigraphic correlations necessary to document depositional heterogeneity are difficult.

Lower Frio reservoir facies are primarily delta-plain distributary-channel and delta-front channel-mouth-bar sandstones. Reservoir compartments in narrow distributary-channel sandstones isolated by low-permeability mudstone facies and channel-mouth-bar sandstones that

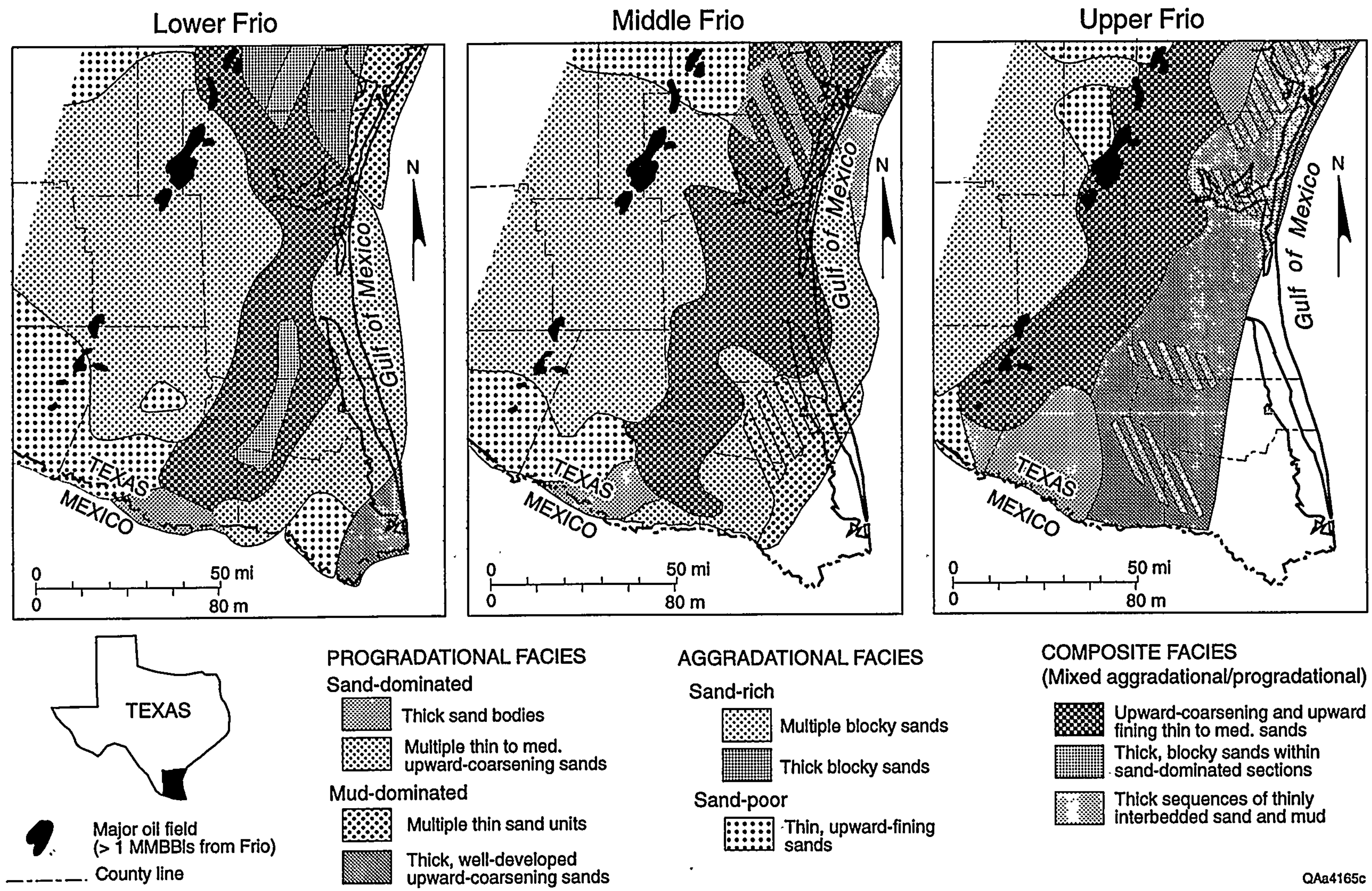


Figure 13. Distribution of aggradational and progradational intervals of the Frio Formation along the Vicksburg Fault Zone oil play. The Frio sediments near the Vicksburg Fault Zone were deposited primarily in moderate- to high-sinuosity mixed-load stream environments of the Gueydan fluvial system. Based on log facies maps by Galloway and others (1982).

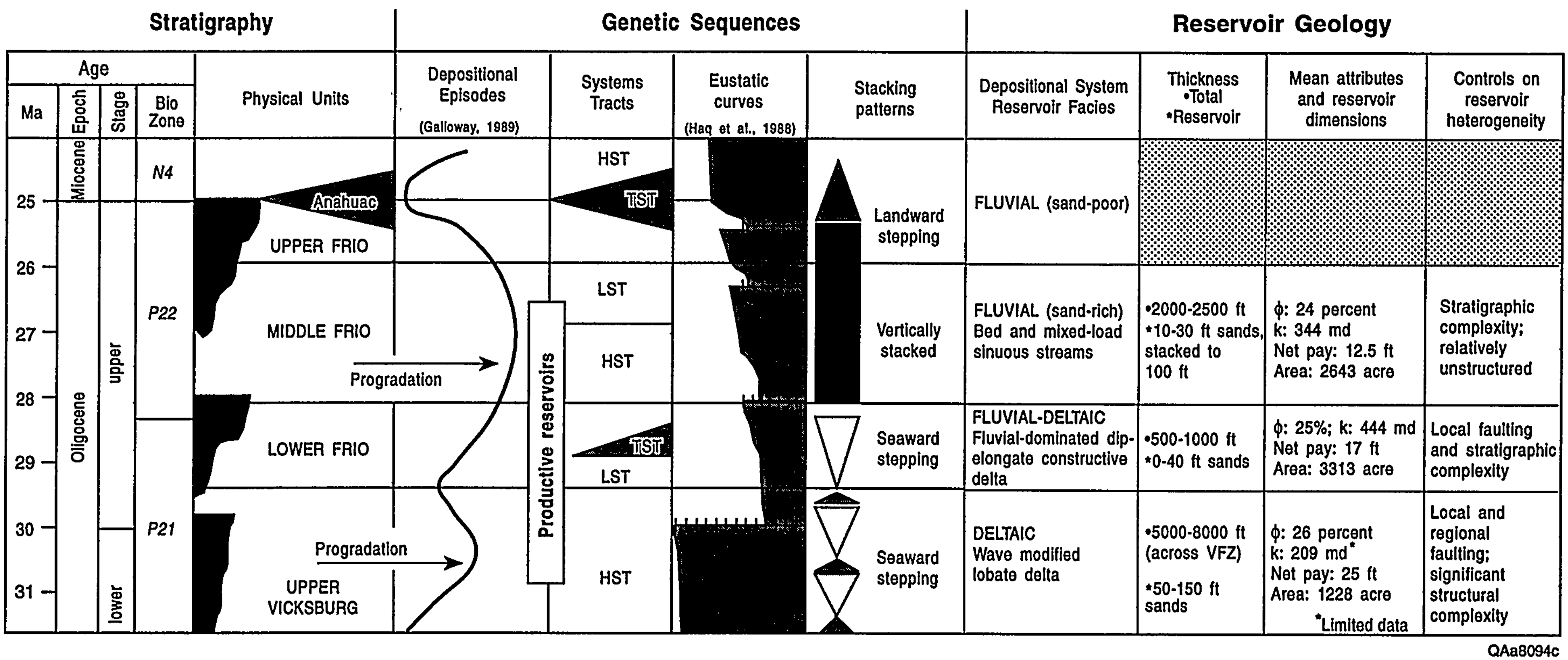


Figure 14. Stratigraphic subdivisions for reservoirs in the Frio Fluvial-Deltaic Sandstone Play and summary of genetic sequence context, reservoir characteristics, oil production, and estimates for remaining oil potential in middle and lower Frio reservoirs.

Table 8: Strategies for play-scale reservoir characterization studies.

Play-scale reservoir characterization
Goals:
• Characterize reservoir variability and degree of heterogeneity
• Develop stratigraphic context for productive reservoir interval
• Identify additional oil potential
Methodology:
• Evaluate engineering data from reservoirs in fields throughout the play trend
• Identify reservoir depositional facies and stacking patterns on a regional scale
• Perform resource calculations to estimate remaining oil volumes present in the play and distribute potential according to stratigraphic interval

pinch out into finer grained delta-front facies are the primary targets for additional oil recovery in the lower Frio section.

Reservoir facies in middle Frio units include channel-fill, point-bar, and crevasse-splay sandstones. Low-permeability subfacies within middle Frio channel fill units act as flow baffles and barriers and create isolated reservoir compartments that represent a significant opportunity for additional recovery. Crevasse-splay deposits, which are of limited areal extent and are laterally separated from channel-fill facies by low-permeability facies, are also potential targets for additional recovery of compartmentalized reserves.

Preliminary Assessment of Reserve Growth Potential in Frio Oil Reservoirs

Strategies for reservoir characterization studies at the scale of the play focused on engineering and geologic data from fields throughout South Texas and are summarized in Table 8. To optimize the calculation of remaining producible resources in the play, reservoir data from fields throughout the play were collected and screened to determine the general engineering

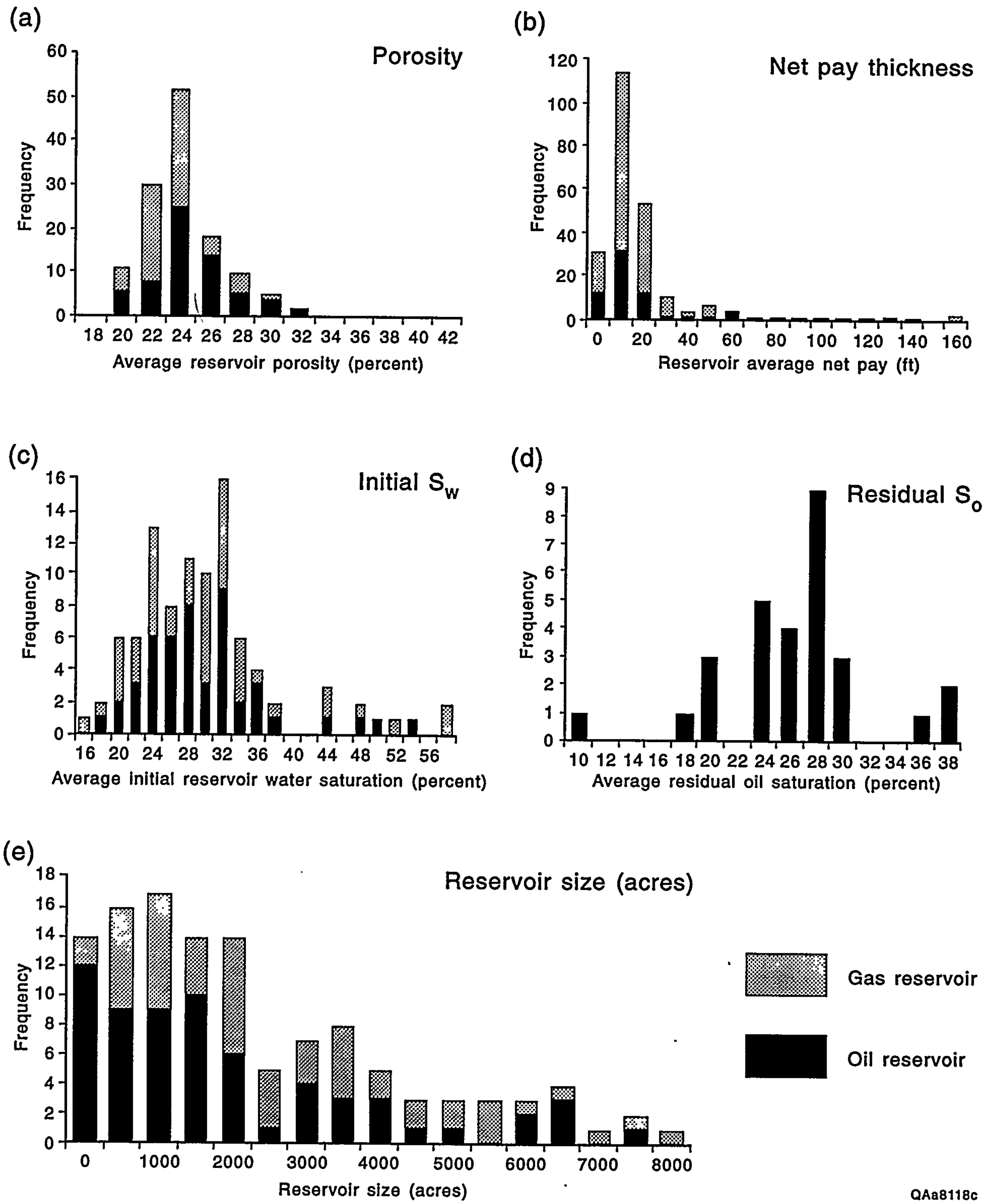


Figure 15. Histograms illustrating distributions for values of porosity (A), initial water saturation (B), residual oil saturation (C), net pay (D), and area (E) from reservoirs throughout the Frio Fluvial-Deltaic Sandstone Play in South Texas.

Table 9. Statistics for reservoir parameters grouped by oil and combined oil and gas data sets.

	Porosity (%)	Initial water saturation (%)	Residual oil saturation (%)	Net pay (feet)	Reservoir area (acres)
Oil reservoirs					
Count	64	48	29	64	65
Minimum	20	18	10	5	133
Maximum	32	54	39.8	146	7,607
Range	12	36	29.8	141	7,474
Mean	**25.3**	**30.6**	**26.9**	**22.8**	**2,170.9**
Standard deviation	2.7	7.4	5.8	25.9	1,890.2
Probability function *(best-fit)*	Normal	Beta	Logistic	Lognormal	Lognormal
Probability function *(alternative)*	Gamma or logistic	Gamma	Normal	Gamma	Exponential
All reservoirs					
Count	346	331	29	242	154
Minimum	19	11.5	10	4	40
Maximum	32	68	39.8	245	26,000
Range	13	56.5	29.8	241	25,960
Mean	**24.2**	**32.0**	**26.9**	**24.3**	**2,549.9**
Standard deviation	1.8	5.5	5.8	29.2	2,860.8
Probability function *(best-fit)*	Logistic	Lognormal	Logistic	Lognormal	Lognormal
Probability function *(alternative)*	Gamma	Beta	Normal	Gamma	Exponential

attributes of this group of fluvial-deltaic reservoirs. Reservoir attribute characteristics of Frio sandstones analyzed for determination of hydrocarbon volumes included porosity, initial water saturation, residual oil saturation, net-pay thickness, reservoir area, and volume of produced fluids (Figure 15). Statistical analysis of engineering attributes for Frio reservoirs throughout the play was completed in the first reporting period of the project (Holtz and others, 1994), and the results are summarized in Table 9.

Reservoir attributes were used to simulate volumes and create probability distributions of original oil in place, original mobile oil in place, and residual oil in place for individual reservoirs throughout the Frio Fluvial-Deltaic Sandstone play. A preliminary assessment of the oil

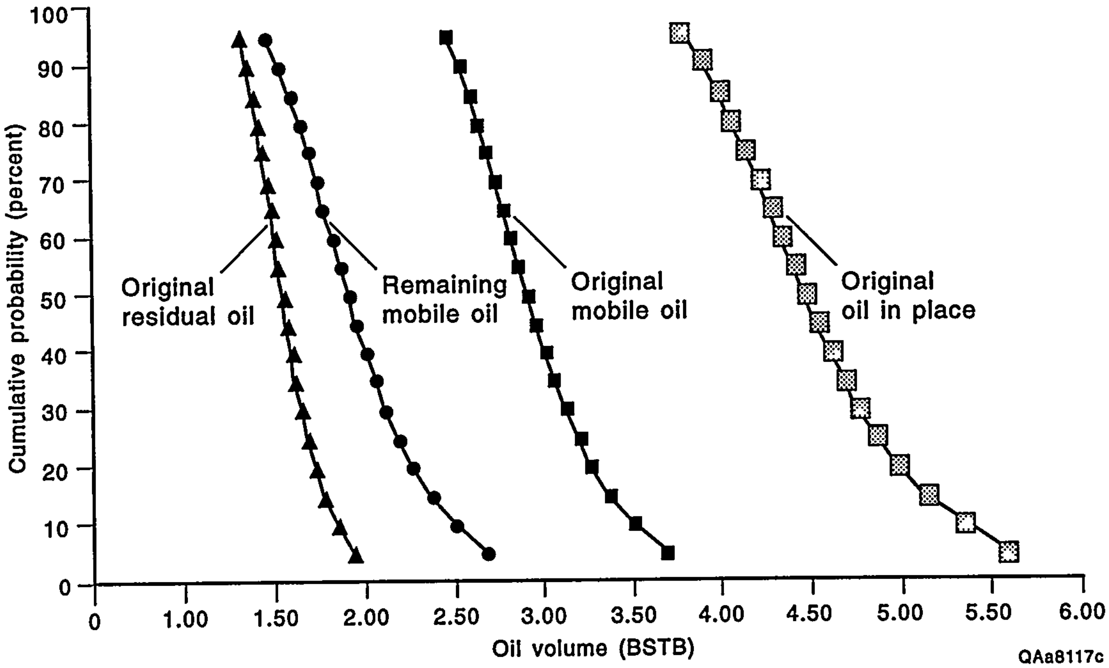


Figure 16. Probability distribution curves illustrating the cumulative probability of original oil in place, original residual oil, original mobile oil, and remaining mobile oil for the Frio Fluvial/Deltaic Sandstone play.

remaining throughout the play was based on these probability distributions (Figure 16). Oil reservoirs in the play are conservatively estimated to contain 1.2 BSTB of remaining mobile oil and 1.5 BSTB of residual oil. These volumes reside in both incompletely drained and untapped reservoirs. These two targets are a substantial volume of oil for redevelopment and reexploration.

Stratigraphic Distribution of Additional Oil Potential

Methodology

The stratigraphic positions of individual fields and reservoir units within the context of the larger scale Frio-Vicksburg genetic stacking sequence were identified to assess the importance of reservoir stratigraphy on hydrocarbon production, recovery efficiency, heterogeneity style, and the potential for compartmentalization of additional oil resources (McRae and Holtz, 1994). Reservoir data were collected from fields throughout the play to evaluate remaining potential in the play as a whole represented by each of these reservoir intervals. Most fields within the play produce from 20 to 50 individual sandstone reservoirs. Reservoirs within a single field commonly

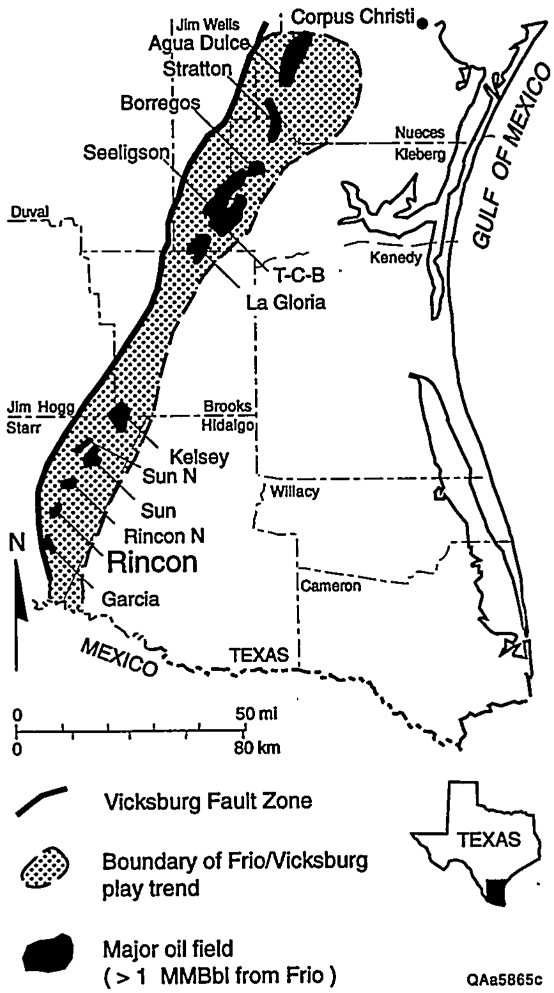


Figure 17. Map of south Texas showing location of fields within the Frio Fluvial-Deltaic Sandstone Play along the Vicksburg Fault Zone. Fields shown include those which have produced more than 1 million Bbls (Modified from Galloway and others, 1983, and Kosters and others, 1989).

include fluvial-channel, distributary-channel, and deltaic sandstones that represent a range of architectural styles, including individual, vertically stacked, and laterally amalgamated geometries. Because depositional facies is a significant control on reservoir attributes, it is important to make a distinction, whenever possible, between reservoir facies types. Subdivision of reservoirs within the play into stratigraphic facies types will result in more accurate characterization of reservoir attributes for each facies type. This analysis provides a regional context that should facilitate the transfer of results from our field-specific studies to other fields and reservoirs in the play.

Strategies for Reservoir Classification

Reservoir sandstones in fields throughout the play that have produced more than 1 MMBO (Figure 17) were identified as belonging to the middle Frio, lower Frio, or upper Vicksburg stratigraphic interval (Figure 7, Table 10). Vicksburg reservoirs are not targets for resource delineation and additional recovery in this project, but some reservoir zones originally classified within the "Frio Fluvial-Deltaic Sandstone Play" in fact represent wave-dominated deltaic sandstones belonging to the Vicksburg Formation. Classification was based on regional geologic setting as well as various other reservoir data available from files at the Railroad Commission of Texas and other nonproprietary sources. Basic criteria such as reservoir depth, geographic and structural location of the field, and depositional

Table 10. List of major oil fields in the Frio Fluvial-Deltaic Sandstone Play. Map numbers refer to figure 7.

FIELD			OIL RESERVOIR PRODUCTION HISTORY				RESERVOIR STRATIGRAPHIC SETTING		
Map No.	County	Field Name	Reservoir Name Number of zones	Disc. Year	Depth (Feet)	CumProd (MSTB)	Fault Block	Strat Unit	Reservoir Facies
1	Hidalgo	Tabasco	Heard FB2	1952	6082	2,587	VK-main+1	LF	Fluvial/Deltaic
2	Hidalgo	Sam Fordyce	Sam Fordyce	1934	2750	7934	VK-main	UF	Fluvial
3	Hidalgo	Sullivan City	Sullivan sand	1939	3437	1692	VK-main	MF	Fluvial
4	Starr	Garcia	6 zones	1942	3748-4132	36304	VK-main	MF	Fluvial
5	Starr	Boyle	Frio 3500'	1940	3500	2408	VK-main	MF	Fluvial
6	Starr	Yturria	2 reservoir zones	1941	4225-4913	4157	VK-main	LF, MF	Fluvial, Fluvial/Deltaic
7	Starr	Dee Davenport	Dee Davenport	1947	4171	1307	VK-main	MF	Fluvial
8	Starr	Ross	Vicksburg	1943	2845	2951	updip/close	V	Deltaic
9	Starr	Rincon	combined zones	1938	4000-5300	58017	VK-main	V, LF, MF	Fluvial,Fluvial/Deltaic, Deltaic
10	Starr	Cameron	lower E sand	1943	4140	3999	VK-main	MF	Fluvial
11	Starr	Rincon, North	3 zones	1940	4376-6000	10527	VK-main	V, LF, MF	Fluvial, Deltaic
12	Starr	Strong	4700 sand	1953	4670	2622	updip/close	MFM	Fluvial
13	Starr	Sun	3 zones	1941	4300-4950	27545	VK-main	LF, MF	Fluvial
14	Starr	Sun North	7 zones	1951	4315-5400	19162	VK-main	V, LF, MF	Fluvial,Fluvial/Deltaic, Deltaic
15	Starr	Sun East	F-4 Sand	1951	5068	1107	VK-main	LF	
16	Hidalgo	La Reforma	La Reforma	1941	6200	1943	VK-main	V	Deltaic
17	Starr	Jaay Simmons	Frio A-1 sand	1947	5770	6096	VK-main	LF	Fluvial
18	Starr	Kelsey South	2 zones	1938	5980	9816	VK-main	V	Deltaic
19	Brooks	Kelsey	2 zones	1938	4700-4800	14424	VK-main	LF	Deltaic
19	Brooks	Kelsey Deep	19 zones	1944	5489-6114	62025	VK-main	V	Deltaic
20	Brooks	Alta Mesa	Garcia sand	1936	2485	9426		UF	Fluvial
21	Brooks	Scott & Hopper	Scott & Hopper	1943	6875	1268	VK-main	V	Deltaic
22	Brooks	Rachal	Rachal	1946	4800	1016	VK-main	MF	Fluvial
23	Brooks	Mills Bennett	D Sand	1953	4436	1168	VK-main	MF	Fluvial
24	J. Wells	LaGloria	6 zones	1945	5950-6985	25373	VK-main	LF, MF	Fluvial , Fluvial/Deltaic
25	J. Wells	Premont	2 zones	1933	3600-3700	3555	VK-main	UF	Fluvial
26	Kleberg	T-C-B	combined 21B	1944	6900-7109	104661	VK-main	LF	Deltaic
27	Kleberg	Seeligson	13 zones	1937	5675-7090	215105	VK-main	LF, MF	Fluvial, Fluvial/Deltaic
28	Kleberg	Borregos	Combined zones	1945	7040	109744	VK-main	V, F	
29	Kleberg	Borregos West	F-82 Segment A	1961	5870	1065	VK-splay	MF	Fluvial?
30	J. Wells	Elpar	2 zones		5130-5494	7815	just updip to VFZ	Frio	Fluvial
31	J. Wells	Ben Bolt	Ben Bolt		5175	9265	just updip to VFZ	Frio	Fluvial
32	J. Wells	Magnolia City	Garcia sand	1951	5642	1980	VK-splay	MF	
33	Kleberg	Big Caesar S.	Pflueger Lower		7562	2537	VK-main	LF	Fluvial/streamplain
34	Kleberg	Bog Caesar	Pflueger Upper	1963	7440	9802	VK-main	LF	Fluvial/streamplain
35	Nueces	Stratton	12 zones	1938	6100-7000	75227	VK-main	LF, MF	Fluvial, Fluvial/Deltaic
36	J. Wells	Tom Graham	Tom Graham	1938	5400	5,721	VK-splay	V	Deltaic
37	J. Wells	Magnolia City N	2 zones	1953	4981-5040	6405	VK-splay	MF	Fluvial
38	Nueces	Agua Dulce	2 zones	1928	6850-6970	45584	VK-main	LF	Fluvial/streamplain
39	Nueces	Brayton	Brayton	1944	7196	7682	VK-main	LF	Fluvial/streamplain
40	Nueces	Clara Driscoll	Clara Driscoll	1935	3800	6913	VK-main	UF	Fluvial/streamplain
41	Nueces	Clara Driscoll S.	J or K	1937	5300	4764	VK-main	LF	Deltaic
42	Nueces	Richard King	2 zones	1937	5400-5600	20754	VK-splay	MF	Fluvial/streamplain
43	J. Wells	Hollow Tree	Hollow Tree	1949	3354	1435	VK-splay	UF	close to strandplain
44	Nueces	Farenthold	Zone L	1946	5886	1967	VK-splay	MF	Fluvial/streamplain
45	J. Wells	Alfred	Alfred	1937	4680	1577	VK-splay	MF	Fluvial/Streamplain
46	J. Wells	Reynolds	Reynolds	1939	4800	2559	VK-splay	MF	Fluvial/streamplain

environment interpreted from log profiles were used to separate Vicksburg units originally grouped within the Frio Fluvial-Deltaic Sandstone Play from Frio reservoirs that are the main focus of this study.

Upper Vicksburg Reservoirs

Data presented here from Vicksburg sandstones include only those reservoirs originally classified as belonging to the Frio Fluvial-Deltaic Sandstone Play. Vicksburg reservoirs along the play trend in South Texas have a shorter development history than do shallower Frio zones and are still actively being exploited and explored by many operators. Resource assessment in this project focused on more mature Frio reservoirs that are in danger of being abandoned before they have produced a majority of their mobile oil. Limited reservoir data from Vicksburg sandstones are shown here to illustrate some basic differences in reservoir geometry between Vicksburg reservoirs and those reservoirs in the overlying Frio section (Figure 18). Reservoir attribute value distributions for Vicksburg sandstones are statistically different than Frio reservoir values. Vicksburg reservoirs are characterized by greater net-pay thicknesses (mean value of 25 ft) and smaller reservoir areas (mean of 1,228 acres). Thicker development of reservoir sandstone facies, as compared to that observed in Frio reservoirs, is expected in delta-front facies that characterize Vicksburg sedimentation. The smaller areal distribution of these reservoir sandstones is most likely a result of the significant faulting associated with Vicksburg deposition that serves to isolate reservoirs into multiple structural compartments.

Lower Frio Reservoirs

Lower Frio reservoirs reside in the stratigraphic section immediately above the Frio-Vicksburg contact in an interval of mixed progradational and aggradational fluvial-deltaic sedimentation. Reservoir sandstones are predominantly dip-elongate, delta-plain distributary-channel sandstones that stack to combined thicknesses of up to 50 ft. These composite units

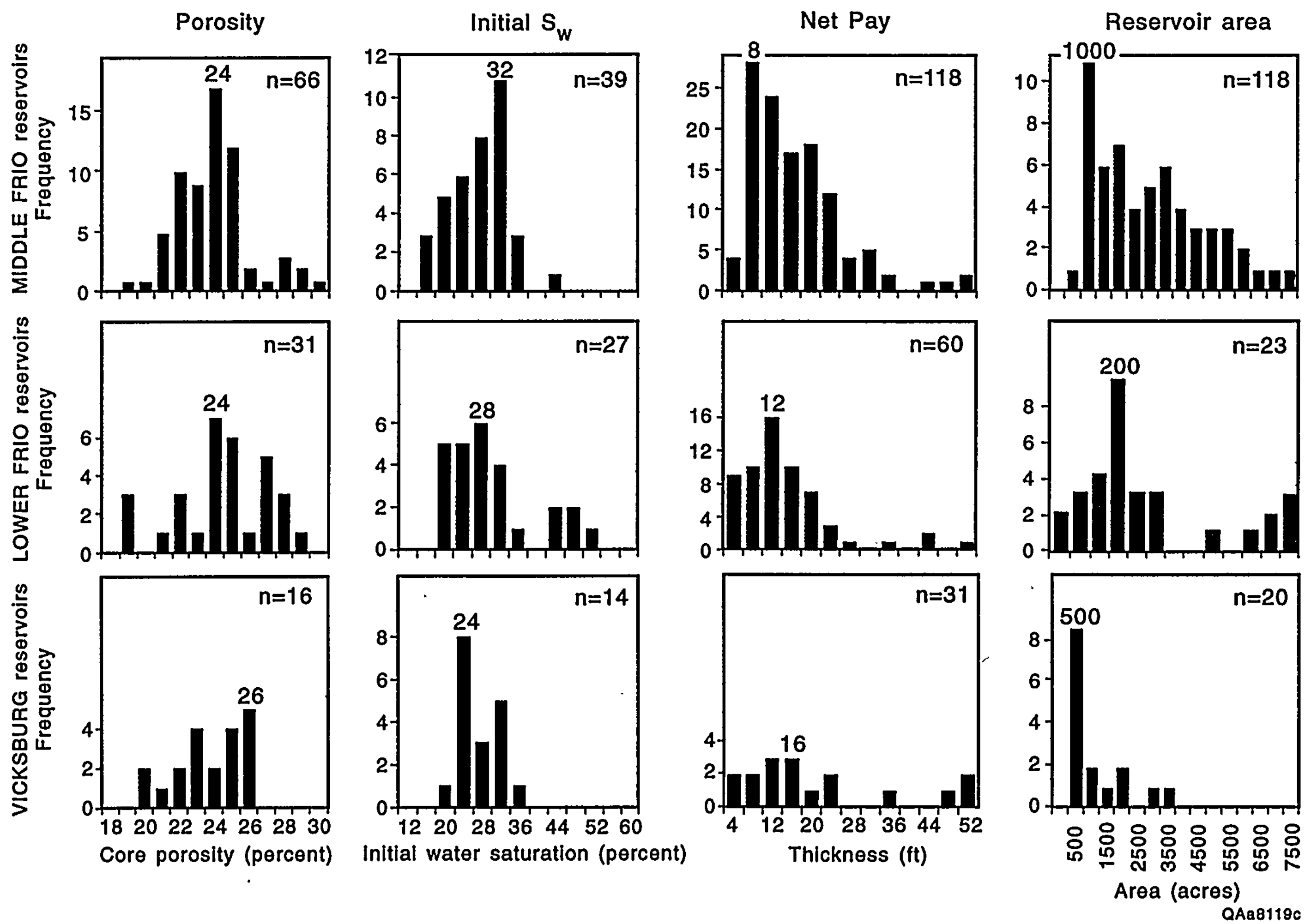


Figure 18. Cumulative frequency histograms illustrating the differences in the distribution of values of porosity, initial water saturation, net pay, and reservoir area for middle Frio, lower Frio, and Vicksburg reservoir sandstones in the Frio Fluvial-Deltaic Sandstone Play.

commonly display an upward-thickening trend that reflects net progradation of the fluvial-deltaic system. Average net pay thicknesses and reservoir areas for lower Frio sandstones are 17 ft and 3,313 acres, respectively (Figure 18). Some of the lower Frio reservoirs included within the play during initial field classification are located rather far downdip to the Vicksburg Fault Zone (basinward from the ancient Frio shoreline) where the lower Frio section becomes expanded and is complicated by faulting. These reservoirs include more deltaic facies and are thicker than their distributary and fluvial channel counterparts located closer to the main fault zone.

Middle Frio Reservoirs

The majority of reservoir sandstones in the Frio Fluvial-Deltaic Sandstone Play are aggradational fluvial channel sandstones located within the middle Frio section. These reservoirs consist predominantly of dip-elongate, upward fining, channel-fill facies with individual thicknesses ranging from 5 to 30 ft and composite stacked thicknesses between 20 and 60 ft. Average net pay and reservoir size for 118 reservoirs from throughout the play are 12.5 ft and 2,643 acres. Mean values for porosity (24%) and initial water saturation (S_w) (31%) are similar for both lower and middle Frio reservoir sandstones, although the distributions of values for these data are distinctive for each (Figure 18).

Distribution of Remaining Recoverable Oil

Overall estimates of the remaining mobile oil resource in reservoirs from middle and lower Frio stratigraphic intervals throughout the play trend in South Texas were calculated by subtracting the volume of oil produced and an estimated residual oil volume from an estimate of original oil in place (OOIP) calculated for each group of reservoirs in the play. OOIP and residual oil for individual reservoirs were calculated using values of acre/ft, porosity, initial water saturation, and formation volume factor (B_{oi}) data specific to each reservoir, and where data were unavailable, mean values derived from the middle Frio and lower Frio reservoir populations were substituted. From these calculations, it is estimated that nearly 1.5 Bbbl of remaining mobile oil, representing more than 40 percent of the OOIP, are still present in these reservoirs (Figure 19). Volumes calculated for both the lower Frio (>800 MMBO) and middle Frio (>580 MMBO) stratigraphic intervals represent significant resource targets. The larger available resource estimated to be present in lower Frio reservoirs may be in part attributed to the greater structural complexity of this deeper portion of the Frio section, which has resulted in greater compartmentalization of oil volumes and therefore reduced recovery efficiencies. Lower Frio reservoirs, because of their greater depths, also have fewer completions than those in the middle Frio and in many cases have not experienced such long production histories. This is because the shallower Frio section was the preferred focus of most early Frio reservoir development.

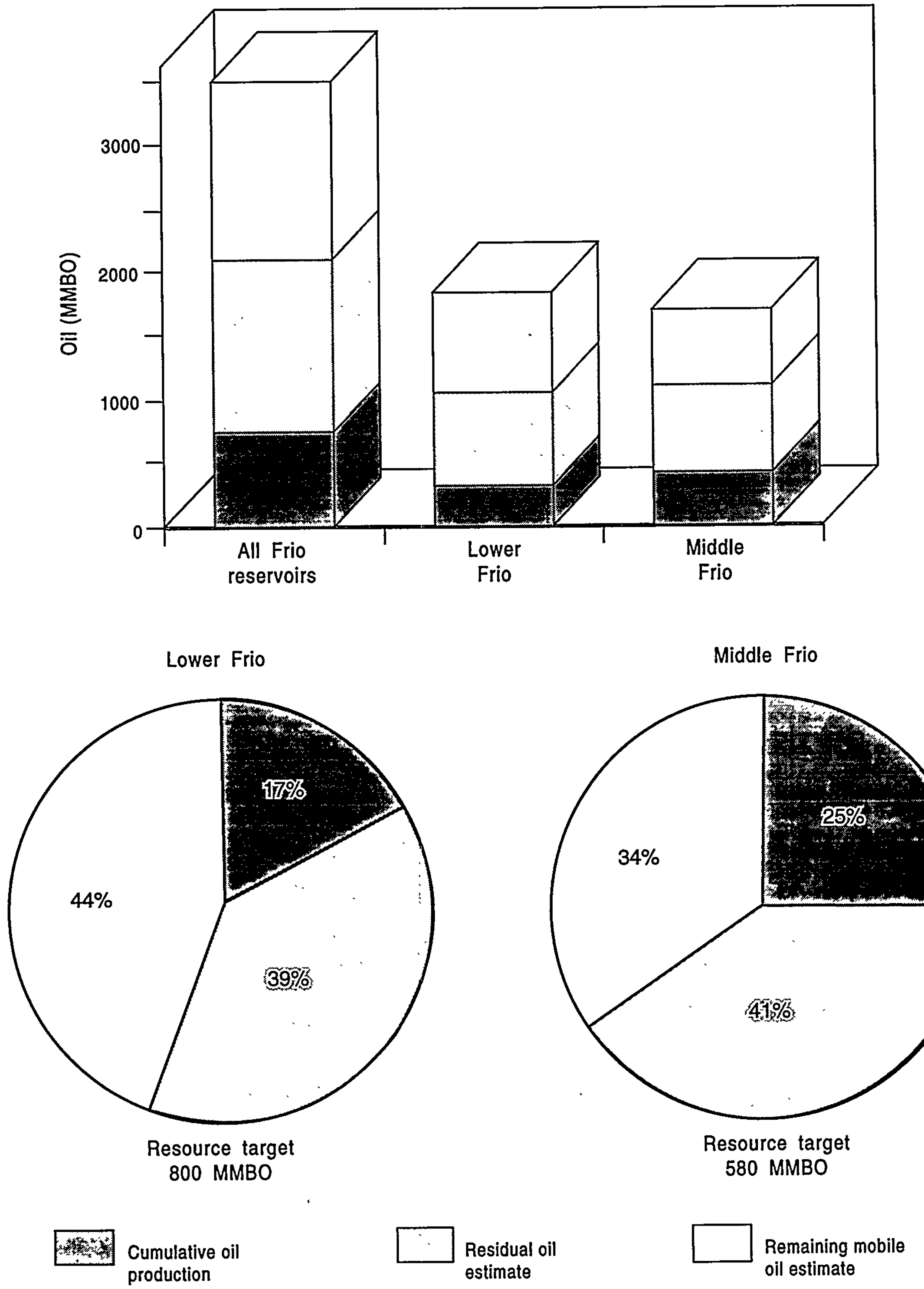


Figure 19. Distribution of the location of oil resources within reservoirs of the Frio Fluvial-Deltaic Sandstone Play in South Texas. Nearly one billion barrels have been recovered in the play, but nearly two thirds of the estimated original-oil-in-place, including more than 1.5 Bbbls of mobile oil, remain in the reservoirs.

RESERVOIR CHARACTERIZATION EXAMPLES FROM RINCON FIELD

L. E. McRae, M. H. Holtz, T. F. Hentz, and C. Chang

Introduction

Reservoirs throughout the Frio play were screened as candidates for detailed characterization studies. The goal of the screening was to find fields containing large infield reserve growth potential and sufficient data to support detailed studies that would demonstrate the value of multidisciplinary characterization techniques by identifying specific opportunities for recompletions or infill drilling. Screening criteria included the (1) size of the reservoir-producing area, (2) density of well completions in individual reservoirs, (3) quality and quantity of existing geologic and production data, (4) availability of 2-D or 3-D seismic coverage, and (5) current level of drilling activity. Fields that contain reservoirs with large producing areas and numerous well bores with a relatively wide completion spacing were excellent candidates for study because they present good possibilities for the identification of bypassed and untapped reservoir compartments. Fields with abundant high-quality geologic, geophysical, and production data, including conventional core and core analysis data, modern well logs, 3-D seismic coverage, and complete reservoir production histories would provide the best chance of success for identifying additional reserve potential through integrated, advanced characterization methods. Recent drilling activity in a field is an indication of an operator's current strategy for reservoir reexploration and additional field development and therefore highlights fields with the best potential for near-term implementation of recommendations resulting from this project.

Two fields, spanning the geographic extent of the play, were selected on the basis of these criteria. Tijerina-Canales-Blucher field (T-C-B) in Jim Wells County, at the north end of the play, and Rincon field in Starr County, at the south end of the play (Figure 17) both contained large reservoirs with abundant data and wide current well spacings and had experienced recent operator activity. Specifically, the Rincon field contained extensive engineering data and some conventional core while a 3-D seismic volume was made available by the T-C-B operator.

The following section describes characterization studies of Rincon reservoirs, focusing on geologic and engineering characterization founded in available core material. A later section discusses integration of geology and geophysics in T-C-B reservoirs.

Location and Geologic Setting of Rincon Field

Rincon field is located in eastern Starr County, Texas, approximately 120 mi southwest of Corpus Christi and 20 mi north of the United States-Mexico border. The entire Rincon field area covers more than 20,000 acres and contains more than 640 wells. The area of investigation covers approximately 5,000 acres in the northern portion of the field, includes nearly 200 wells, and is limited to productive reservoir sandstones within the Frio section (Fig. 20).

The general structure in the shallow Frio section at Rincon is characterized by a northeast-trending, downthrown asymmetric rollover anticline that plunges gently to the northeast and is bounded to the west by the Sam Fordyce/Vanderbilt Fault, a major growth fault associated with the large Vicksburg Fault Zone system (Fig. 21). Frio production associated with the shallow structure is both stratigraphically and structurally controlled. Hydrocarbons are trapped in zones within the rollover anticline downdip of the major growth fault and exist in multistoried and multi-lateral sandstone reservoirs that form complex stratigraphic traps draped over an anticlinal nose.

More than 50 individual productive reservoirs within the stratigraphic interval from 3,000 to 5,000 ft have been identified and mapped across the Rincon field area, and they range in dimension from only a few acres to complex, interrelated reservoir systems that are present across the entire field. Individual reservoir units occur both as narrow channel-fill sandstones isolated vertically and laterally by very low permeability overbank facies and floodplain mudstones and as large channel complexes consisting of multiple thin sandstone units that combine into a single large communicating reservoir. The variability in sandstone geometries and the complex multilateral and multistacked nature of these reservoirs provide excellent potential for identifying additional hydrocarbons that have been isolated in untapped and incompletely drained reservoir compartments. In this project our Rincon field study focused on two reservoirs as type examples.

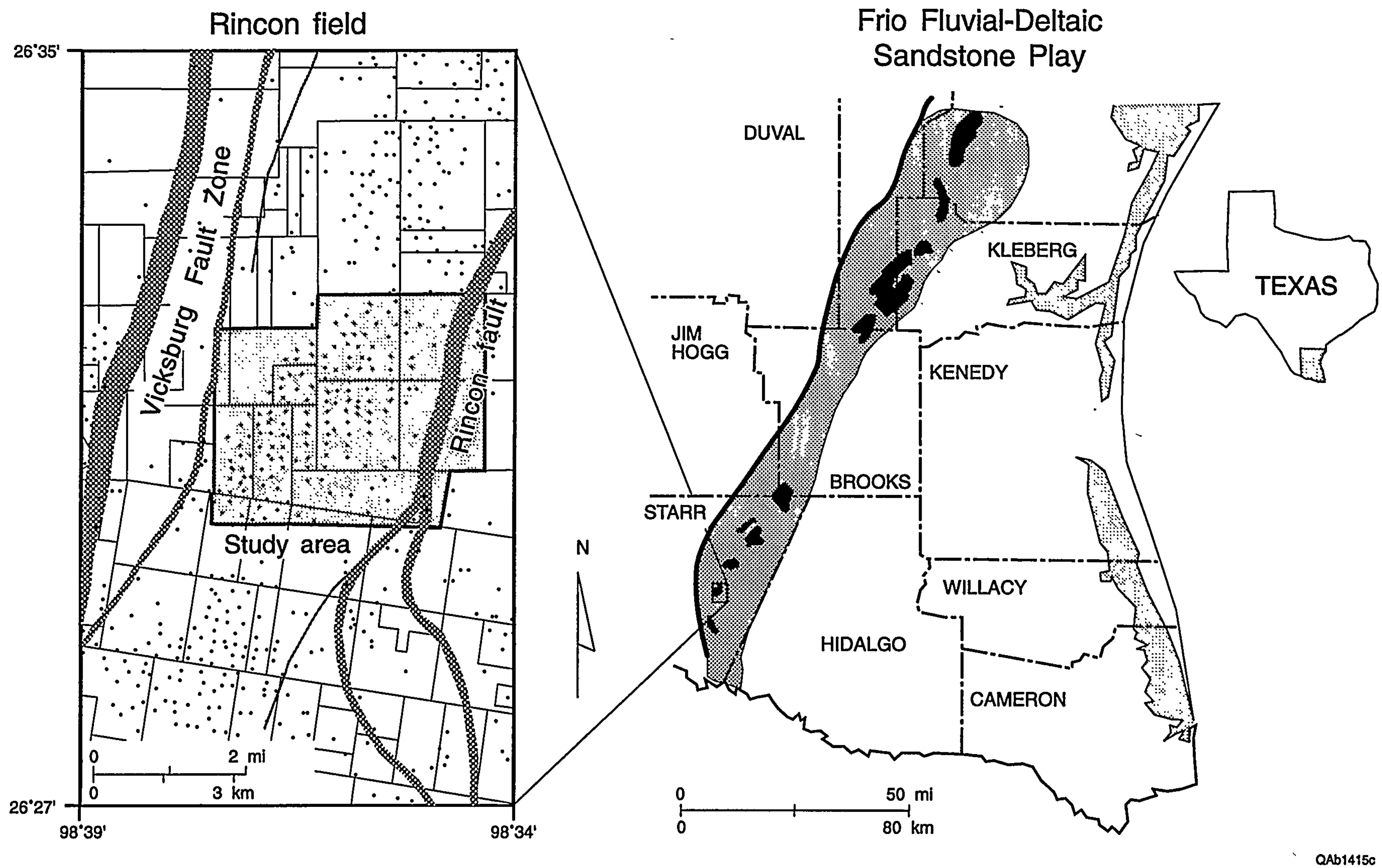


Figure 20. Location map of Rincon field within the Frio Fluvial-Deltaic Sandstone Play and area of field selected for detailed reservoir studies.

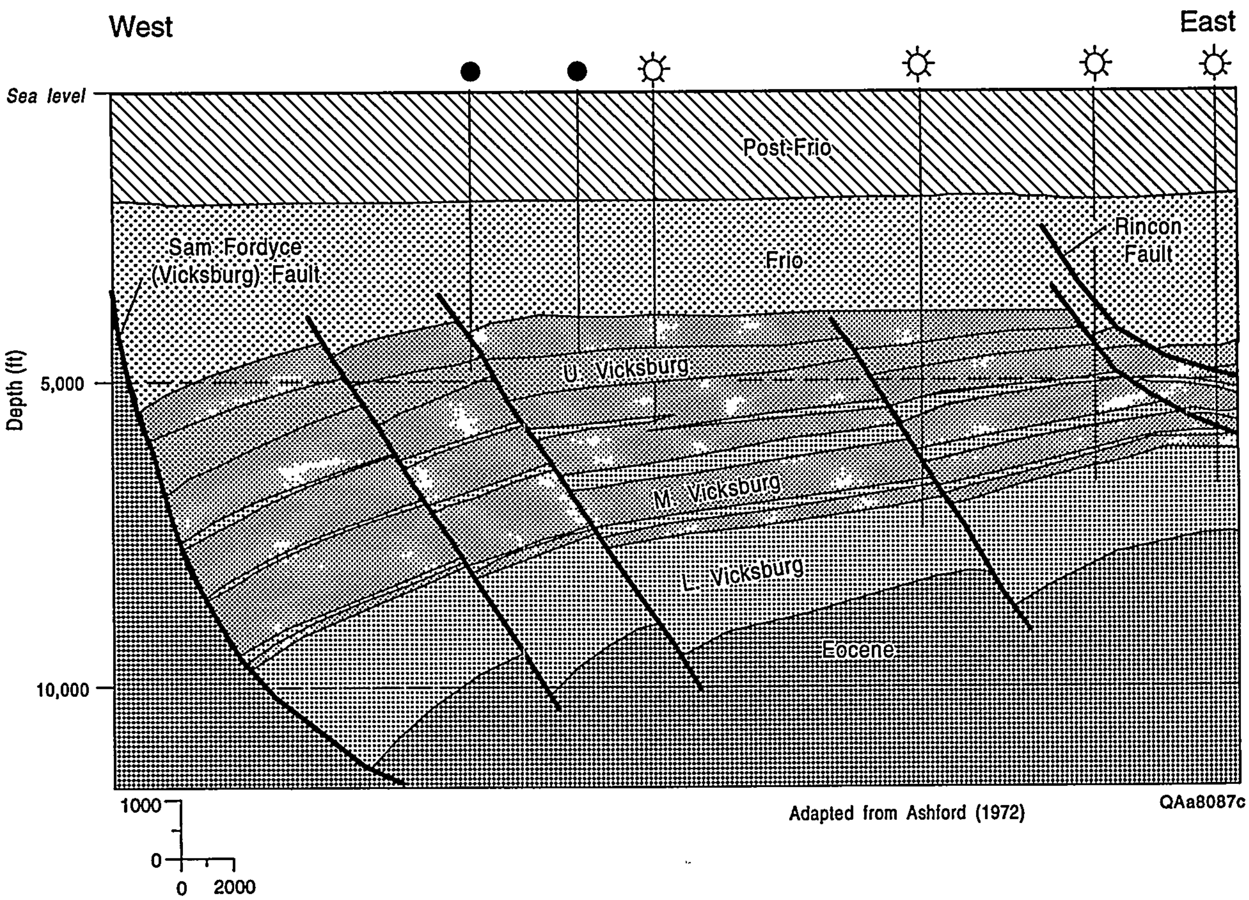


Figure 21. Generalized west-to-east cross section through Rincon field illustrating structural setting of a representative field in the Frio Fluvial-Deltaic Sandstone Play (adapted from Ashford, 1972).

Selection of Reservoirs for Detailed Study

Because of the large number of reservoirs in Rincon field and the limited nature of this study, a subset of two major reservoir intervals was selected for detailed characterization. These reservoirs, the Frio D and E intervals, are the two most highly prolific reservoir zones in Rincon field, having produced a combined 22 MMbbl of oil from the leases studied. Additionally, the stratigraphic complexity of these intervals, consisting of vertically stacked and laterally coalescing sandstone lobes, provides ideal conditions for the isolation of oil accumulations in isolated compartments, many of which are now incompletely drained or completely untapped.

The Frio D and E intervals also exhibit low recovery efficiencies. Taken together, the four reservoirs in the Frio D interval have a current recovery efficiency of only 28 percent, whereas the four reservoirs in the E interval have a recovery efficiency of 38 percent. Both intervals were waterflooded, with substantially different results. Waterflooding of the E reservoirs account for 21 percent of cumulative production, whereas waterflooding of D reservoirs only accounts for 2 percent of total production.

Reservoir Characterization Methodology

A complete, all-encompassing reservoir characterization methodology developed during this study was presented in Holtz and others (1996). The methodology takes a systems approach, viewing geologic, geophysical, and engineering data inputs with a goal of determining reserve growth potential. The four basic steps in the methodology are to (1) determine reservoir architecture, (2) establish fluid flow trends, (3) integrate fluid flow history and reservoir architecture, and (4) evaluate reserve growth potential. As with all field studies the comprehensiveness of techniques applied is dependent on the available data. In Rincon field, only those techniques that made maximum use of available data were applied. Details of the specific methodology used on Rincon reservoirs was presented in McRae and others (1995) and pertinent information is summarized in each of the four following sections.

Determine Reservoir Architecture

Importance of the Genetic Sequence Analysis Approach

Development of a detailed regional stratigraphic and structural context for a reservoir is a critical step in evaluating its potential for secondary hydrocarbon recovery. Sequence-stratigraphic concepts provide a chronostratigraphic framework in reservoir studies that is useful in delineating the structure of reservoir flow units and also provide a means of transporting results of reservoir studies to other fields in analogous stratigraphic settings. Construction of a reservoir framework at the sequence and parasequence scales provides a means for the natural packaging of strata into genetic units that correlate well to petrophysically defined units at the interwell scale (Tyler and others, 1992). Definition of lithologic and diagenetic reservoir flow-unit architecture of fluvial-deltaic sandstones within the context of a well-defined sequence-stratigraphic framework can provide a model to predict the distribution and continuity of permeable zones in other reservoirs deposited in analogous depositional settings. Previous detailed work on the regional geology of the Frio depositional sequence in South Texas (Galloway and others, 1982; Galloway, 1977, 1982, 1989a, 1989b) and several recent reservoir characterization studies of Frio gas reservoirs (Jirik, 1990; Kerr, 1990; Kerr and Jirik, 1990; Kerr and others, 1992; Grigsby and Kerr, 1993) provide an excellent context in which to study individual facies components of oil-bearing reservoirs in the Fluvial-Deltaic Sandstone play.

In Rincon field, a prominent low-resistivity marker interpreted to be an important flooding surface separates the thicker, generally upward-coarsening progradational units in the lower Frio third-order unit from thinner, dominantly aggradational channel deposition in the middle Frio section. The majority of Frio production at Rincon occurs within a 1,000-ft interval of interstratified sandstones and mudstones. Laterally persistent low-resistivity surfaces interpreted to represent floodplain or interdeltaic mudstones separate primary reservoir sandstone zones that are commonly 50 to 150 ft thick. These fourth-order reservoir zones are, in turn, composed of several individual, 5–30-ft thick channel-fill units (Fig. 22). The major cause of stratigraphic complexity and compartmentalization of hydrocarbons in these sandstones is their variability in geometry and the multilateral and multistacked nature of individual fifth-order reservoir units. Fourth-order reservoir units at Rincon field were evaluated to identify specific reservoir styles that are representative of those observed throughout the play. Understanding the specific stratigraphic context of the reservoirs selected for study will facilitate transfer of results of this study to other reservoirs, other fields, and other analogs beyond the Frio in South Texas.

Stratigraphic positions of important reservoir units in Rincon field within the context of the larger scale genetic stacking sequence were identified to assess the importance of reservoir stratigraphy to hydrocarbon production, recovery efficiency, heterogeneity style, and the potential for compartmentalization of additional oil resources. Twenty-four low-resistivity markers representing 7 major (fourth-order) bounding surfaces and 17 secondary (fifth-order) surfaces in

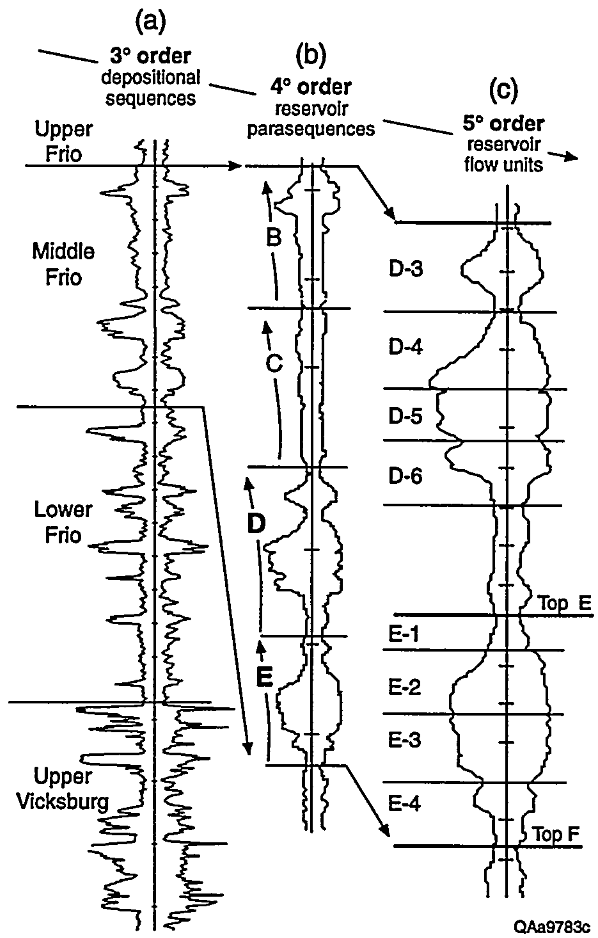


Figure 22. Spontaneous Potential/resistivity type logs illustrating (a) the general depositional sequence for the productive Frio–upper Vicksburg reservoir interval, (b) the stratigraphic context of the middle Frio reservoir sequence in Rincon field, and (c) the reservoir nomenclature of individual producing units within the Frio D–E interval selected for detailed study.

184 wells were correlated in a series of stratigraphic cross sections across the field study area. Wireline core data representing more than 1,500 analyses from more than 100 wells in the Rincon field study area were assigned to individual upper Vicksburg, lower Frio, and middle Frio reservoir subunits and evaluated to assess heterogeneity within each of these major reservoir stacking intervals.

Ascertaining Internal Reservoir Stratigraphy

Ascertaining internal reservoir stratigraphy requires five separate tasks. These include (1) identification of regional stratigraphy and preliminary fieldwide stratigraphy, (2) the identification of lithofacies from available core material, (3) petrographic examination of cores, (4) the correlation of the finest-scale genetic units resolvable with the given data, and (5) determining the geometry and depositional history of sandstones within these fine-scale genetic units.

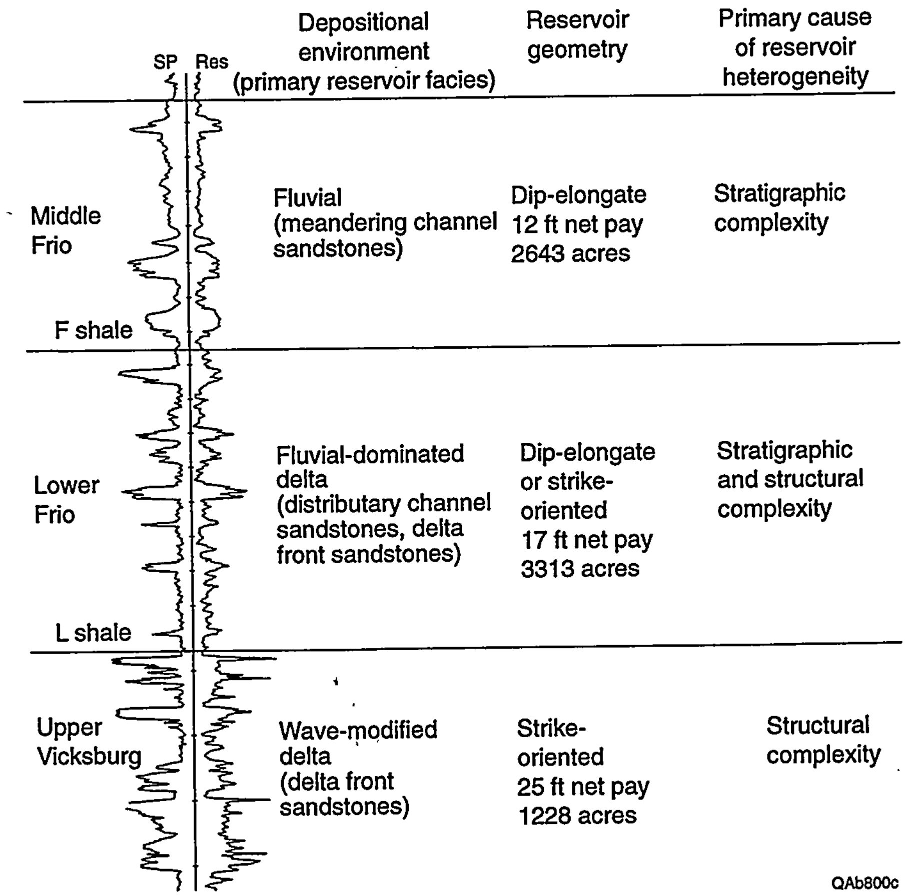


Figure 23. Depositional systems and reservoir attributes of the Rincon field reservoir section.

Regional Stratigraphy

A typical log from the productive reservoir interval in Rincon field is shown in Figure 23. The F shale marker represents the division between lower and middle Frio reservoirs, as it is located where a change in sedimentation style occurs from deposition of net progradational sandstone packages to primarily aggradational sand deposition. Reservoirs in the middle and lower Frio sections consist of multiple stacked pay sandstones. Interpretations supported by SP log profiles and whole core studies indicate that the dominant reservoir lithofacies are fluvial channel-fill deposits. Individual reservoir sandstones (fifth-order units) within each zone are commonly 5–30-ft-thick channel-fill units and have lateral dimensions ranging from 1,000 to more than 6,000 ft. The major cause of reservoir complexity and compartmentalization of hydrocarbons is a result of this variability in sandstone geometry and the multilateral and multistacked nature of these individual reservoir units. Characteristics specific to each stratigraphic reservoir interval are discussed in more detail below.

Upper Vicksburg reservoirs

Vicksburg reservoirs in Rincon field include the sandstone unit below the L shale shown in the lower portion of the log interval illustrated in Figure 23. These reservoirs consist of thick progradational (seaward-stepping) deltaic sandstone deposits that occur in packages 50 to 150 ft thick and are separated by 50- to 200-ft-thick intervals of mudstone. Primary reservoir facies are channel-mouth-bar sandstones that are interbedded with prodelta mudstone and siltstone. Individual upward-coarsening channel-mouth-bar deposits are generally less than 50 ft thick and stack to produce repetitive cycles that can reach 150 to 200 ft in thickness.

Vicksburg reservoirs in Rincon field are not currently targets for resource delineation and additional recovery through our studies, which emphasize characterization of stratigraphic heterogeneity. This is because their deposition was strongly influenced by faulting associated with the development of the Vicksburg Fault Zone (Coleman and Galloway, 1991), and correlations necessary to document depositional heterogeneity and stratigraphic compartmentalization in these reservoirs are difficult. Our reservoir studies are focusing on the structurally uncomplicated Frio reservoir interval, where there is better potential for identifying lateral facies heterogeneity and stratigraphic compartmentalization, and there are also much more data available.

Lower Frio reservoirs

In Rincon field, the Lower Frio stratigraphic interval appears to represent deposition in an aggradational to mixed aggradational and progradational setting within the Gueydan fluvial system. The lower Frio reservoir interval shown in the log in Figure 23 is interpreted to correspond to an interval of mixed progradational and aggradational sedimentation. The F shale is taken to mark the boundary between the mixed aggradational and progradational reservoirs in the lower Frio section and the purely aggradational deposition that characterizes the middle Frio section.

Reservoir facies in the lower Frio interval are interpreted to represent predominantly fluvial channel and delta-plain distributary-channel sandstones. Channel units are distributed as elongate, dip-parallel belts. Individual, upward-fining channel sandstone packages, as evidenced by bell-shaped SP log profiles, range from 5 to 20 ft thick, and commonly stack to produce amalgamated units that have vertical thicknesses of 10 to 50 ft. These stacked sandstone packages commonly display an upward-thickening trend. Although sandstone units are, on average, thicker than in middle Frio reservoir zones, sandstone body continuity is generally less than in middle Frio fluvial channels. This may be because distributary channel-fill sandstones are commonly narrower and are flanked laterally by sandstone-poor interdeltaic facies. Low-permeability mudstone facies locally encase and compartmentalize or isolate individual reservoir sandstones and create reservoir compartments that are the primary targets for additional oil recovery in the lower Frio interval.

Middle Frio reservoirs

The depositional pattern in the middle Frio interval in Rincon field is characterized by sedimentation dominated by fluvial aggradation. Deposition in dip-elongate channel systems developed across the low-relief Oligocene Gulf Coastal Plain toward the shoreline in a direction from northwest to southeast (Fig. 24). Middle Frio reservoir facies consist primarily of dip-elongate fluvial channel-fill sandstones and are separated by nonreservoir facies that include levee siltstones and floodplain mudstones. Productive middle Frio reservoirs in Rincon field occur both as individual narrow channel-fill units isolated vertically and laterally by low-permeability overbank and floodplain facies and as large channel complexes with multiple sandstone lobes. Sandstones have individual thicknesses ranging from 5 to 30 ft but are commonly stacked into composite units with gross thicknesses between 20 and 60 ft. Low-permeability subfacies within the channel fill are responsible for development of multiple reservoir compartments that may represent significant opportunities for additional recovery.

Description of Lithofacies from Core

After the regional and general fieldwide context of reservoir intervals were established, available core material was studied to tie lithofacies to log response, aid in interpreting

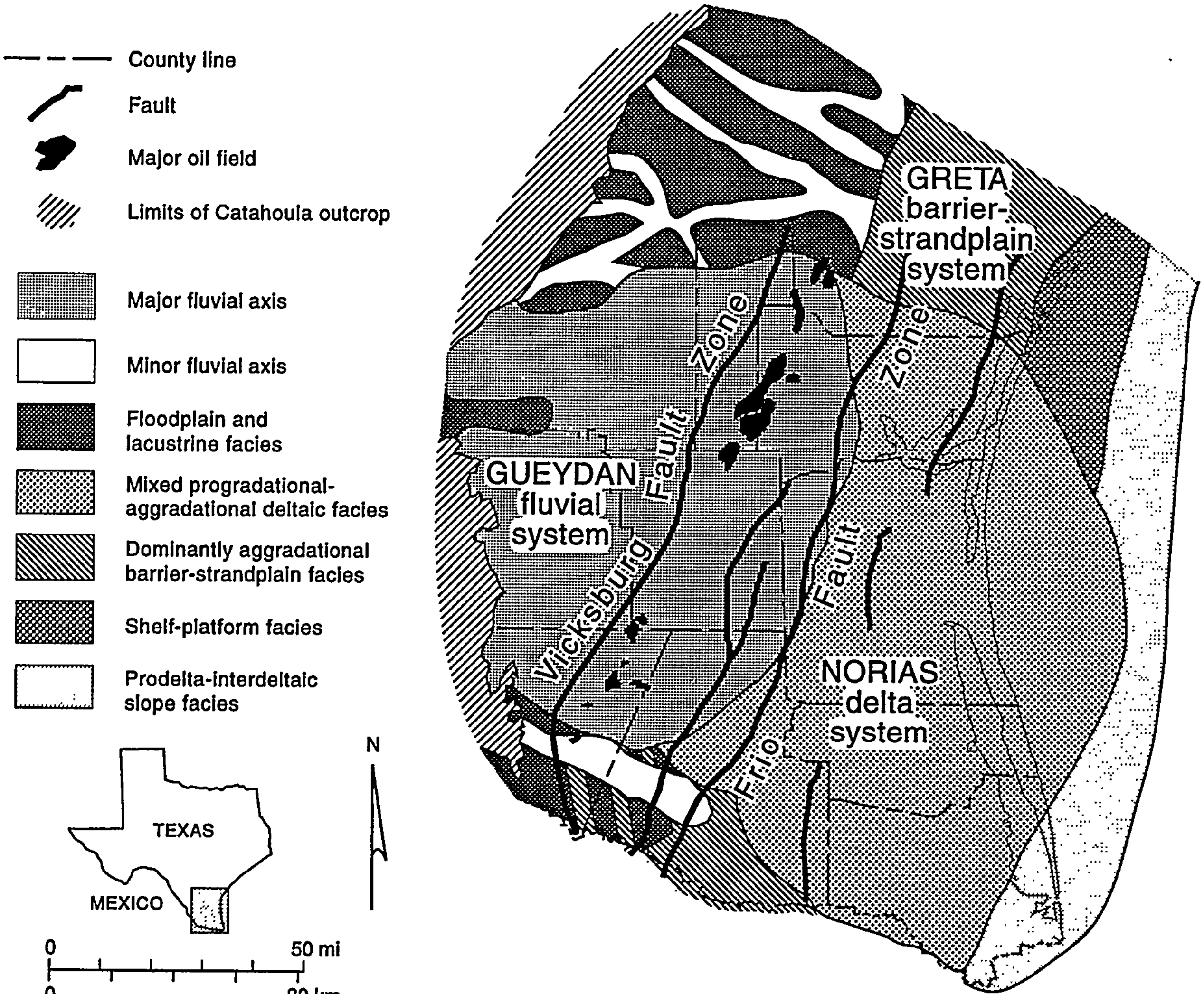


Figure 24. General distribution of the Norias delta and Gueydan fluvial depositional systems responsible for deposition of the Frio stratigraphic unit. The Frio sediments in the vicinity of the Vicksburg Fault Zone were primarily deposited in moderate- to high-sinuosity mixed-load stream environments of the Gueydan fluvial system. (Map distribution from Galloway and others, 1982.)

depositional facies, examine the petrographic character of reservoirs and acquire special petrophysical measurements. Detailed core studies were conducted on conventional core cut from the T. B. Slick A133 and A149 wells, located in lease block 231 near the center of the field study area. A total of 155 ft of core was examined. Core descriptions from both wells, along with porosity and permeability profiles derived from conventional core analysis data, are illustrated in Figures 25, 26, and 27. Detailed core description and sampling were limited to the Frio D and E reservoirs. The core from well 149 includes the stratigraphic interval through most of the

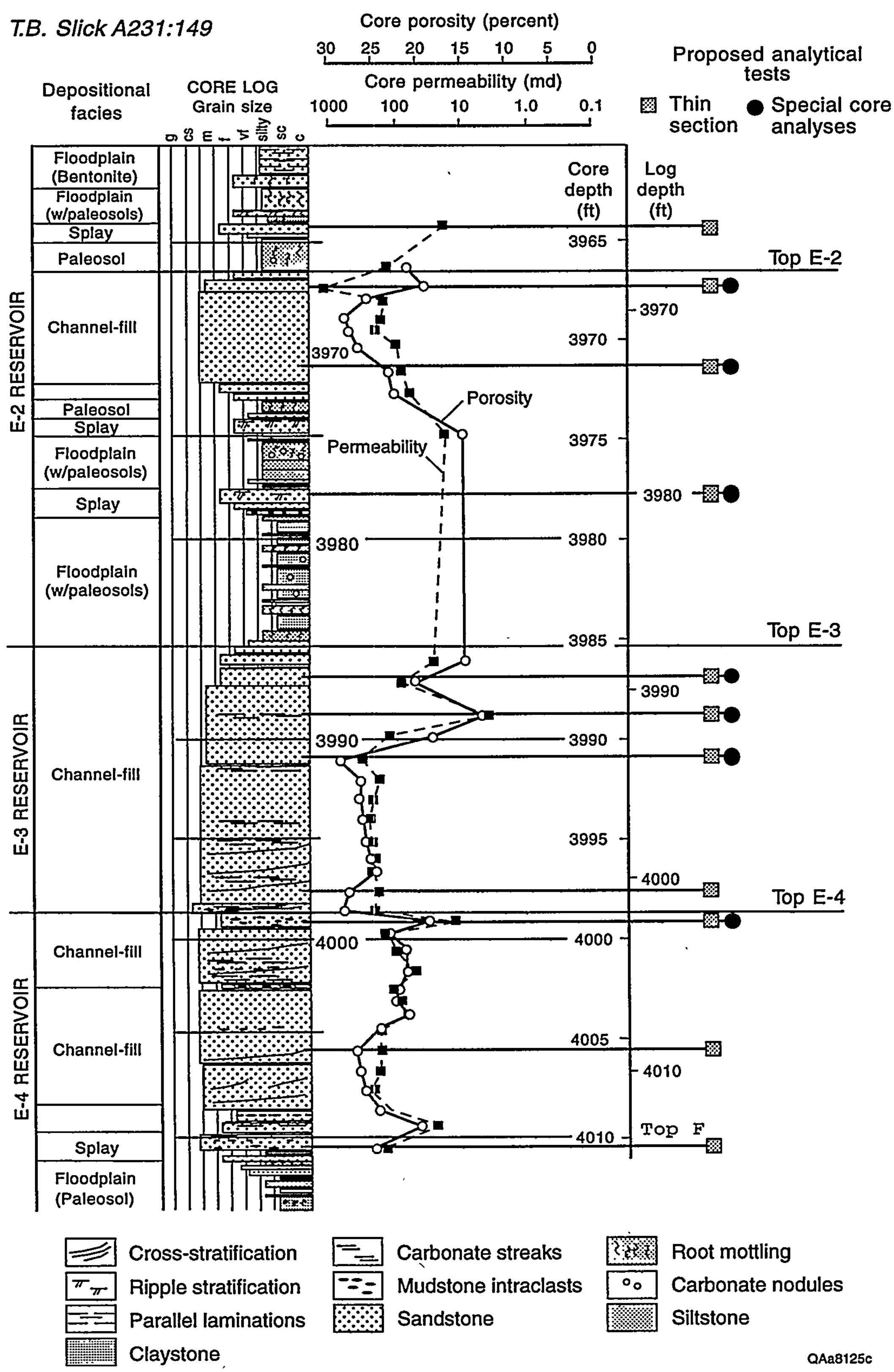


Figure 25. Graphic core log, T. B. Slick 231:149 well, Frio E reservoir zone, along with corresponding facies interpretations, core analysis data for porosity and permeability, and location of samples selected for petrographic and special core analyses.

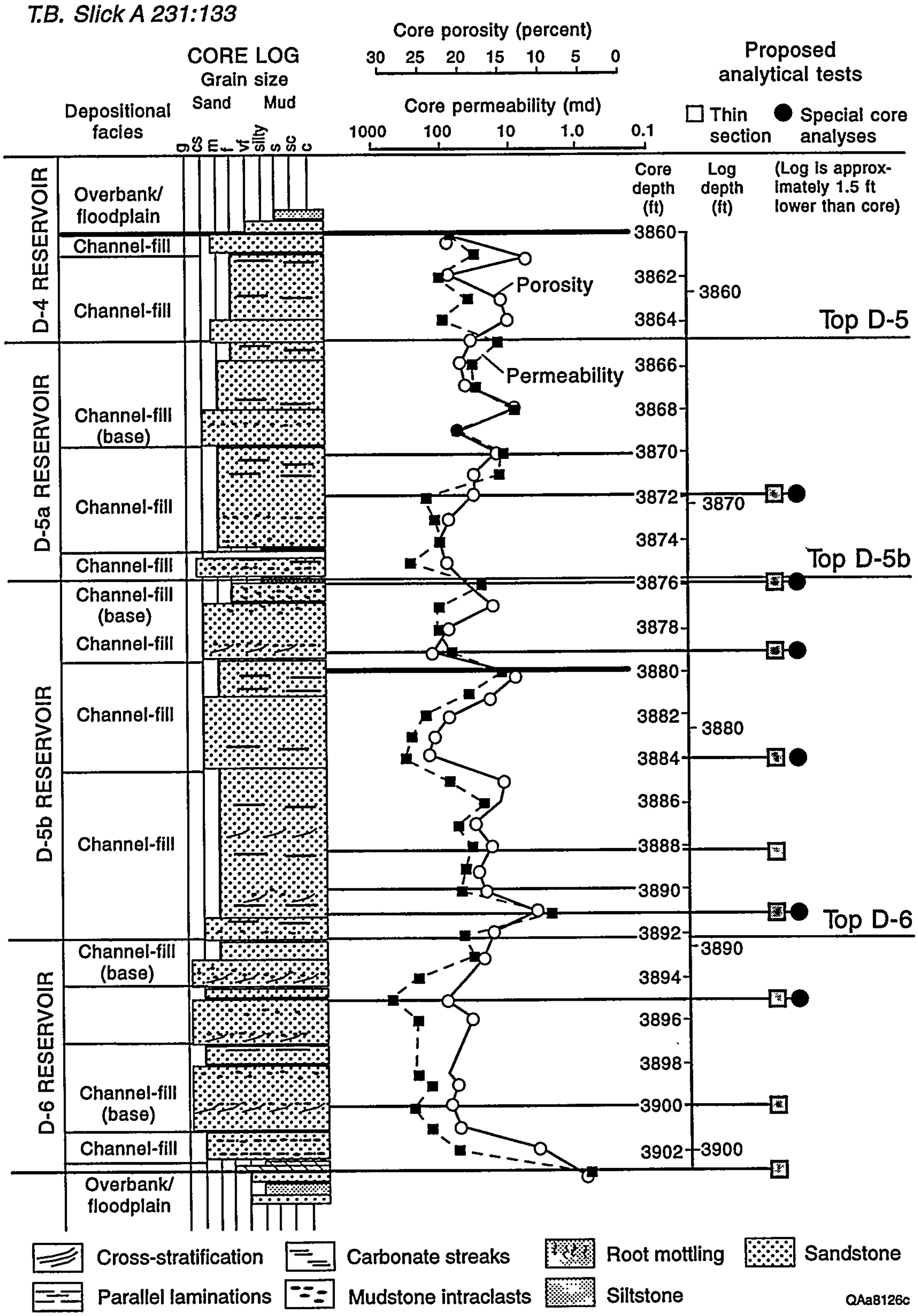


Figure 26. Graphic core log, T. B. Slick 231:133 well, Frio D reservoir zone, along with corresponding facies interpretations, core analysis data for porosity and permeability, and location of samples selected for petrographic and special core analyses.

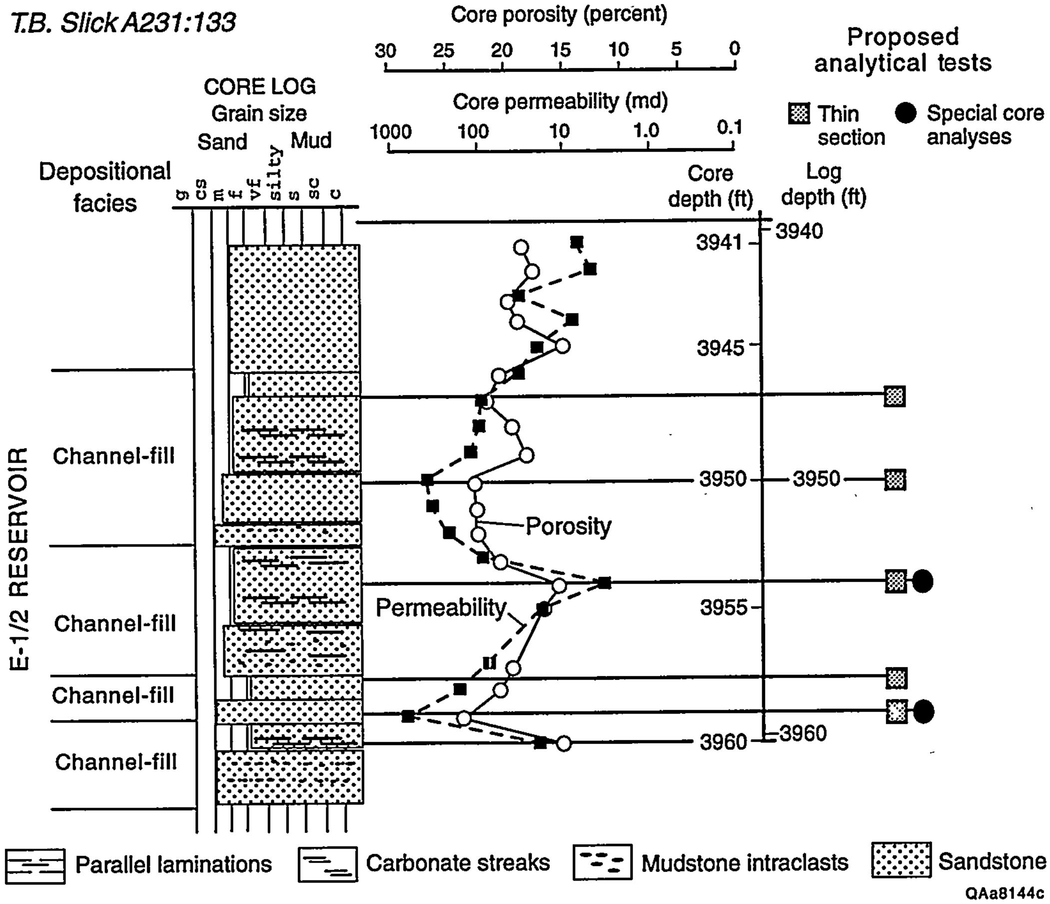


Figure 27. Graphic core log, T. B. Slick 231:133 well, Frio E reservoir zone, along with corresponding facies interpretations, core analysis data for porosity and permeability, and location of samples selected for petrographic and special core analyses.

E reservoir zone, and the well 133 core represents the depth interval through the D reservoir and the top portion of the E reservoir. Based on core observations, there are no obvious distinctive differences in sandstone mineralogy, textures, or facies types between the Frio D and E reservoir zones. Vertical facies sequences of channel-fill sandstones, splay sandstones, and floodplain mudstone units recognized in both cores support our interpretations of fluvial depositional environments determined from electric log correlations and reservoir mapping.

Mudstones

Floodplain units present between sandstone facies consist of red-brown mudstone, silty mudstone, and siltstone that commonly exhibit color variegation and various degrees of bioturbation, root molds, and calcareous nodule development that are all diagnostic of alteration associated with soil-forming processes. Caliche formation and the reddish coloration of the mudstones reflect deposition in well-drained and sparsely vegetated floodplains and suggest semiarid climatic conditions. The abundance of pedogenic features also indicates that interchannel areas were subaerially exposed and drowned only during infrequent flooding.

Darker gray and laminated mudstones with a conspicuous lack of pedogenic features that characteristically indicate abandoned-channel facies were not observed in core. Because of the very limited whole core available, this is not surprising. Abandoned-channel facies are interpreted to be present within the field study area but cannot be distinguished solely on the basis of electric log signature. Mudstones that cannot be correlated between wells may be inferred to represent abandoned-channel facies.

Some floodplain mudstones are green-gray and possess a mottled waxy texture typical of an altered bentonite (e.g., 3,960–3,961 ft, Fig. 25). Volcanic activity was occurring in northeastern Mexico throughout the Oligocene, and other workers have noted the presence of bentonites and high concentrations of volcanic glass in the Frio reservoir section in other South Texas fields (Kerr and Jirik, 1990; Grigsby and Kerr, 1993).

Sandstones

Both channel-fill sandstones and crevasse splay sandstone facies were observed in core. Individual channel-fill sandstones range from 5 to 12 ft thick, and all exhibit upward-fining textures. Splay sandstones are less than 1 ft thick (e.g., 3,964 ft, 3,974 ft, 3,980 ft, Fig. 25) and appear more uniform or slightly upward coarsening in grain size. The thin (< 2 ft) nature of these splay facies suggests that crevasse development was localized and did not provide a significant contribution to sand deposition.

In addition to these primary facies distinctions, three channel subfacies, basal, middle, and upper channel-fill, could be identified on the basis of texture and sedimentary structures. The basal channel-fill facies refers to the lowermost portion of the channel-fill unit, is commonly coarser grained than the rest of the channel-fill (medium- to coarse- grained sandstone), and may include a gravel lag consisting of intraformational clasts of mudstone and calcareous nodules (e.g., 3,997 ft, 4,010 ft, Fig. 25, 3,875 ft, 3,894 ft, Fig. 27). The thickness of the basal facies of the channel-fill is typically less than 1 ft. The middle channel-fill facies comprises the majority of the channel-fill unit and has a grain size that normally ranges from medium to fine. Evidence of cross-stratification is very faint or not observable in core. The upper channel-fill facies consists of the top few feet of a channel-fill unit, is finer grained than the underlying middle channel-fill sandstone (fine to very fine sandstone to silty sandstone), and has rare evidence of ripple-drift stratification.

Vertical profiles of porosity and permeability values are plotted alongside each of the described cores to assist in identification of different petrophysical rock types present in the various depositional facies. These profiles also illustrate the comparison of reservoir properties between channel-fill sandstones and splay sandstones and among the various channel subfacies. Channel-fill sandstones have lower permeability in the basal channel fill, where there is commonly a well-developed mud chip zone (e.g., 3,997 ft, 4,009 ft, Fig. 25; 3,876 ft, 3,891 ft, Fig. 26). Porosity and permeability systematically increase upward through the middle portions of the sandstone unit, and then they are typically reduced near the top of a sandstone where there is a reduction in grain size (e.g., 3,970 ft to 3,967 ft, 4,009 ft to 4,003 ft, Fig. 25; 3,876 ft to 3,870 ft, Fig. 26). Thin sandstones that are interpreted to represent crevasse splays or perhaps distal channel margins are generally finer grained than channel-fill facies and therefore possess lower porosity and permeability (e.g., 3,964 ft, 3,974 ft, Fig. 25).

Commonly two sandstone units are stacked together, and the presence of a mud chip zone at the base of the upper sandstone unit results in a significant reduction of permeability (e.g.,3,997 ft, Fig. 25; 3,875 ft, Fig. 26). Another rock type that has not been designated a separate facies consists of middle or upper channel facies sandstones that contains abundant carbonate cement. Thin (<1 ft) cement zones observed in core appear to be a localized phenomenon, but where present, correspond to lower porosity and permeability values (e.g., 3,989 ft, Fig. 25; 3,871 ft, Fig. 26).

Petrographic Studies

Overview

Petrographic studies on Rincon Frio sandstone samples were conducted to determine framework compositions, textures, and cement types and distribution to evaluate the degree to which diagenesis is controlling reservoir quality in the Frio D and E reservoir sandstones in Rincon field. General descriptions of pore geometry of these sandstones were also completed to supplement results from special core analyses.

Methods

The guiding approach to petrographic analyses was to conduct them within the context of the reservoir stratigraphic framework. Twenty-two representative samples from core in both wells were selected to provide good data coverage of each of the various reservoir facies and petrophysical rock types present within the Frio D and E reservoir zones in the two wells (Figs. 25, 26, and 27). Samples selected from the T. B. Slick 231/149 well were taken from the end trims of 1-inch-diameter core plugs so that petrographic parameters viewed in thin section could be directly compared to laboratory-derived porosity and permeability values. Several of these plugs were also selected for special core analyses. There are core analysis data for the T. B. Slick 231/133 core, but the original plugs from which these measurements were taken were not available. New core plugs were drilled from adjacent available core material for selected additional core measurements, and thin-section chips were taken from the ends of these new core plugs.

Composition of Frio D and E reservoir sandstones was determined by standard thin-section petrography supplemented by scanning electron microscopy (SEM) using an energy dispersive X-ray spectrometer (EDX). Petrographic characteristics, including texture (grain size, sorting), detrital mineralogy, authigenic cements, and porosity type and distribution, were observed and quantified by point counts of 21 of the 22 thin sections. A total of 200 counts was made on each thin section. Thin sections were stained for potassium feldspar and carbonates. Major categories of whole-rock volume counted include (1) primary detrital framework grains (quartz, feldspars, and rock fragments), (2) authigenic cements, (3) accessory minerals, (4) detrital clay matrix, and (5) pore space. Size estimates of framework grains were performed by visually comparing thin sections to standardized grain-size charts. Both potassium feldspar (orthoclase) and plagioclase grains were categorized as fresh, leached, calcitized, or vacuolized/sericitized. Authigenic cements were identified by mineral composition and categorized according to their distribution within intergranular pores or within secondary pores formed by dissolution of preexisting framework constituents. Porosity was identified as primary or secondary according to similar criteria. Primary and secondary porosity were identified in the context of the inferred diagenetic history of the samples. SEM and EDX analysis of samples enabled visualization of mineral and pore morphology and precise identification of clay mineralogy.

Texture

Frio sandstone samples from Rincon field range from lower fine grained (0.15 mm) to pebbly lower medium grained (0.3 mm), with most samples being in the upper fine to lower medium sandstone range (0.21 to 0.3 mm). The mean grain size of all samples is 0.25 mm, the size that marks the border between the fine and medium sand categories. Sorting ranges from very poor to moderate; most samples are poorly sorted. Sand grains are angular to subrounded.

Framework mineralogy

All Frio sandstones examined are mineralogically immature, and most samples are classified as feldspathic litharenites by the sandstone classification of Folk (1974) (Fig. 28a). The dominant framework constituents of most Frio Rincon samples are rock fragments, which on average compose one-half of all framework grains. The average composition of essential framework grains (normalized to 100 percent) from all 21 core samples is 17 percent quartz, 33 percent feldspar, and 50 percent rock fragments ($Q_{17}F_{33}R_{50}$). Compositions of samples from Rincon field generally coincide with compositions of other shallow (3,500 to 6,000 ft) Frio reservoir sandstones of the lower Texas Gulf Coast (Grigsby and Kerr, 1993). Deep (6,000 to 18,000 ft)

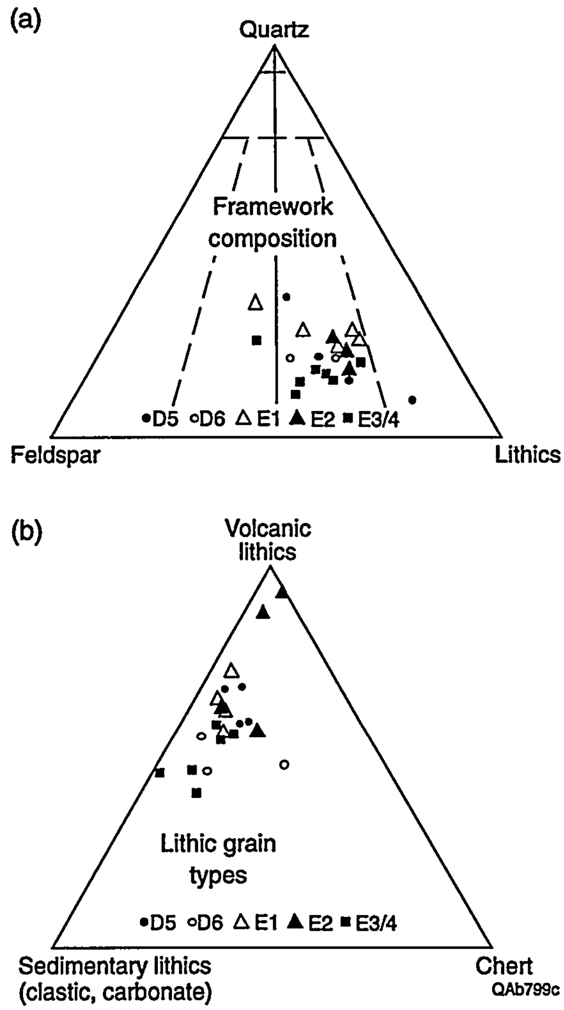


Figure 28. Ternary diagrams showing composition of Rincon D and E reservoir sandstones from thin-section petrography. (a) Percentages of quartz, feldspar, and lithic fragments. (b) Composition of lithic fragments, including volcanic rock fragments, sedimentary rock fragments, and chert.

Frio samples of the lower Texas Gulf Coast tend to be richer in quartz grains than the shallow Rincon samples, probably due to the greater degree of dissolution of feldspar and feldspar-rich rock fragments in the deep samples and resulting relative enrichment in quartz (Bebout and others, 1978; Loucks and others, 1986).

Most lithic fragments in the Frio Rincon samples are volcanic rock fragments (VRFs) (Fig. 28b), which compose an average of 59 percent of all rock fragments (range: 10 to 94 percent) and 18.7 percent of whole-rock volume (range: 6.5 to 26.0 percent). Coarser grained VRFs contain either plagioclase or predominantly orthoclase within a fine-grained groundmass and were derived from contemporaneous active volcanic areas in northern Mexico and West Texas (Loucks and others, 1986). Lindquist (1976) determined that most Frio VRFs from the Rio Grande Embayment are rhyolite and trachyte clasts, although numerous VRFs of basic

Table 11. Summary of petrographic data for Rincon sandstones.

					Framework constituents (normalized percent)			Lithic grain compositions (%)				Visual porosity estimates			
Depth	Res. zone	Depositional facies	Gr. size (mm)	Phi size	Q	F	R	Vrf	Srf	Crf	$CaCO_3$ cement (%)	1° Ø (%)	2° Ø (%)	Total Ø (%)	% total 2°
3872.0	D-5a	Channel-mid	0.15	2.75	11	30	59	26	1	9	7.5	1.5	20	21.5	93
3876.0	D-5a	Channel-base													
3879.0	D-5b	Channel-mid	0.21	2.25	16	41	43	19	0.5	5.5	4	0	27	27	100
3884.0	D-5b	Channel-mid	0.3	1.75	16	30	54	22	2.5	6.5	4.5	4.5	17.5	22	80
3891.0	D-5b	Channel-base	0.3	1.75	25	27	48	19	0	8.5	14	0.5	16.5	17	97
3895.0	D-6	Channel-mid	0.30	1.75	11	35	54	17	1	14.5	15	2	14	16	88
3900.0	D-6	Channel-base	0.30	1.75	13	30	57	22	4.5	10.5	22.5	2	4	6	67
3945.0	E-1	Channel-top	0.15	2.75	7	45	48	24.5	0.5	7	7.5	1	14.5	15.5	94
3950.0	E-1	Channel-mid	0.30	1.75	12	36	52	23.5	0	11	4.5	3.5	15	18.5	81
3954.0	E-1	Chan-mid (cc)	0.30	1.75	14	37	49	21.5	.05	8.5	32.5	0	1.5	1.5	100
3959.0	E-1	Channel-base	0.30	1.75	10	43	47	17.5	2	7.5	14	2	14.5	16.5	88
3964.0	E-2	Splay	0.21	2.25	21	46	33	15	0	0	0	0	2.5	2.5	100
3967.3	E-2	Channel-top	0.21	2.25	38	53	27	9.5	2	2	10.5	12.5	4.5	17	26
3969.3	E-2	Channel-mid	0.30	1.75	23	34	43	24.5	0.5	1.5	4	18.5	8	26.5	30
3974.6	E-2	Splay	0.21	2.25	15	27	58	22	4	6	24.5	5	7	12	58
3987.0	E-3	Channel-top	0.21	2.25	18	29	53	14.5	8	8	8.5	2.5	25.5	28	91
3988.7	E-3	Chan-mid (cc)	0.21	2.25	21	30	49	17.5	1	9.5	25	1	5.5	6.5	85
3990.9	E-3	Channel-mid	0.21	2.25	19	28	53	20	1.5	9.5	9	12.5	13.5	26	52
3997.5	E-3	Channel-mid	0.25	2	21	23	56	21	1	10	8	12.5	9.5	22	43
3999.6	E-3	Channel-base	0.25	2	16	34	50	16.5	4.5	11	5.5	3.5	18	21.5	84
4008.3	E-4	Channel-mid	0.30	1.75	23	25	52	13	1.5	13	9	11.5	18	29.5	61

Key: Q-quartz, F-feldspar, L-lithics, Vrf-volcanic rock fragment, Srf-sedimentary rock fragment (clastic), Crf-carbonate rock fragment (intraformational), 1° Ø-primary porosity, 2° Ø-secondary porosity, Total Ø- total visual porosity (1° + 2°), all values in counts (total 200 cts/sample), 2° Ø (% total)-percentage of total visual porosity that is secondary.

composition, such as basalt clasts, were observed in this study. In the outcrop equivalent to the Frio, sandstones contain VRFs of felsic and intermediate compositions as well as basalt grains (McBride and others, 1968). Rare VRFs in coarsest samples preserve original vesicular volcanic texture, with chert spherules now filling vesicles. Many isolated well-rounded chert and rare chalcedony grains within the Frio Rincon samples are probably vesicle fills. Sedimentary rock fragments (SRFs), which constitute an average of 41 percent of all rock fragments in Frio Rincon samples (14.7 percent of whole-rock volume), include carbonate rock fragments (CRFs), chert, and rare shale, siltstone, and sandstone clasts. CRFs and chert predominate, with only minor to trace amounts (<2 percent of whole-rock volume) of the other lithic types. CRFs are micritic and are interpreted to have been derived from caliche (Lindquist, 1976). Frio Rincon samples also contain trace amounts of metamorphic rock fragments (MRFs), generally phyllite or slate.

Plagioclase is by far the most abundant feldspar in the samples, composing an average of 82 percent of all feldspars and 17.6 percent of whole-rock volume (range: 12.0 to 27.0 percent) (Table 11). Frio samples contain an average of 3.9 percent (whole-rock volume) orthoclase (range: 1.0 to 11.0 percent). Both plagioclase and orthoclase grains occur in several states of alteration (in order of abundance): fresh, vacuolized/sericitized, leached, and calcitized. Leaching of entire feldspar grains was a prominent stage in the diagenetic evolution of the Frio Rincon reservoirs, and partially and wholly leached grains contribute to reservoir porosity and permeability. Both topics are discussed more fully in subsequent sections.

Quartz grains are third in relative abundance of all framework grains (average of 10.6 percent of whole-rock volume; range: 4.5 to 16.5 percent) (Table 11). Most quartz grains are single crystals. Rare grains in each sample, however, are polycrystalline, indicating, along with the sparse MRFs, a minor metamorphic source terrain for Frio Rincon samples.

Accessory minerals in Frio Rincon samples include, on average, only trace amounts of muscovite and biotite, and nearly 1 average whole-rock percent of patchy organic material (Table 11). Pyrite is locally finely disseminated in matrix and organics.

Detrital clay matrix

Frio Rincon reservoir rocks are low in clay matrix content, and it is not a significant factor in controlling reservoir quality. Samples contain an average whole-rock volume of 2.2 percent clay matrix (range: 0 to 9.0 percent) (Table 11). Illite and/or illite/smectite are the dominant clay minerals. One Frio Rincon sample (3964.1 ft) is notable in its abundance of detrital illite and/or illite/smectite matrix. This sample contains 48.5 whole-rock percent matrix, which is interpreted to be the alteration product of volcanic ash in a bentonite bed. Because this bed does not represent reservoir rock, its matrix content was not included in computations of the average content of the reservoir facies. Volume of pore-filling matrix (detrital clay) and clay cements is consistently low in the samples and is not considered to be a significant influence on reservoir quality.

Cements

Authigenic cements collectively constitute a range of 4.0 to 32.5 percent of the whole-rock volume in the Frio Rincon samples, with a mean value of 11.6 percent (Table 11). Authigenic cements include (in order of abundance) non-ferroan calcite, chlorite, and kaolinite. There are also trace amounts of quartz and feldspar overgrowths and illite/smectite grain-rimming cement. Calcite dominates other cements, with an average of 11.2 percent, close to the average sample content of all cements. Chlorite and kaolinite constitute an average of 0.4 and 0.1 percent of all cements, respectively.

Calcite cement occurs as an intergranular cement with a sparry, non-poikilotopic crystal habit. Most samples are only sparsely cemented and contain abundant, commonly oversized (as much as 0.45 mm in greatest dimension), pores. Isolated patches of sparry calcite with locally crenulate (corroded) rims are characteristic of most samples. In heavily calcite-cemented samples (low porosity), cemented areas are commonly as much as two framework-grain diameters wide and four grain diameters long. Some partially leached feldspar grains and VRFs contain calcite within intragranular dissolution voids; however, such grains were point-counted as calcitized feldspar and VRF, respectively, and they are relatively rare. Calcite is a significant Frio cement phase in other fields of the lower Texas Gulf Coast (Lindquist, 1977; Bebout and others, 1978; Loucks and others, 1986; Grigsby and Kerr, 1993).

The whole-rock volume of chlorite cement varies from 0 to 4.0 percent. Chlorite and illite/smectite are mostly grain-rimming cements but also fill a small percentage of intergranular pore space. Chlorite crystal morphology typically takes the form of platelets. Kaolinite, a decomposition product of feldspar, is present in only 6 of the 21 Frio Rincon samples and occurs as a patchy intergranular cement.

Quartz overgrowths are sparsely distributed in some samples and absent in others. Where present, overgrowths are consistently thin and poorly developed and probably represent incipient quartz cementation in these shallow Frio samples. Loucks and others (1986) noted that quartz overgrowths first developed in Frio sandstones between depths of 5,000 and 6,000 ft, deeper than the 3,870- to 4,000-ft range of the Rincon field samples. In Seeligson and Stratton fields of South Texas, minor amounts of quartz overgrowths occur in Frio samples from 4,000 to 6,500 ft deep (Grigsby and Kerr, 1993). In their comparative study of Tertiary sandstones along the entire Texas Gulf Coast, Loucks and others (1986) also observed that quartz overgrowths are more abundant in samples having more quartz grains. Moreover, quartz grains are consistently the least abundant of framework grains in Frio samples from the lower Texas Gulf Coast (Bebout and others, 1978). Therefore, minimal overgrowth development in the Frio Rincon samples may also be in part due to their low quartz content. Feldspar overgrowths are rarer than quartz overgrowths in Frio Rincon samples. However, this cement is characteristic of other Frio reservoirs and is inferred to have developed at shallow depths (<4,000 ft) (Loucks and others, 1986).

Porosity

Total porosity observed in thin section varies from 2.5 to 29.5 percent of whole-rock volume, with an average value of 17.3 percent. Secondary porosity composes most of visible thin-section porosity in the Frio Rincon samples. It varies considerably from 2.5 percent of whole-rock volume in heavily calcite-cemented samples to 28.0 percent in heavily leached samples (average: 15.7 percent). Secondary porosity is developed as voids within partially dissolved framework grains (mainly feldspars and VRFs) and as oversized pores that once contained framework grains and/or calcite cement. Little primary porosity (average: 1.5 percent) is preserved in the samples. It exists as small intergranular voids at least partially lined with chlorite or calcite crystals growing into the voids within areas of closely spaced framework grains. However, in most cases it is difficult to identify primary porosity because such textural relations are not present. The Rincon samples underwent at least two stages of dissolution of framework constituents and calcite, the dominant pore-filling cement (Fig. 29). Therefore, textural relations typically cannot be used to confidently establish whether observed porosity is original.

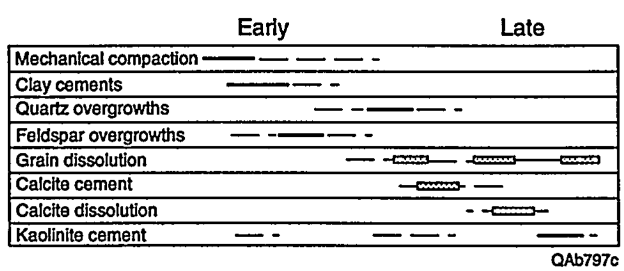


Figure 29. Diagenetic sequence diagram, Rincon D and E reservoir sandstones.

Diagenetic sequence

The primary diagenetic events in the burial history of Frio Rincon sandstones were (1) early mechanical compaction, (2) precipitation of clay (chlorite, illite/smectite) grain-rim cements, (3) development of quartz and feldspar overgrowths, (4) dissolution of primarily feldspar and feldspar-rich VRFs (probably contemporaneous with step 3 and steps 5-8), (5) calcite cementation, (6) dissolution of calcite cement, (7) migration of hydrocarbons through the reservoir rock, and (8) precipitation of kaolinite cement.

The diagenetic sequence of mineralization of the Frio Rincon samples was deduced from textural relations among the framework grains and cements observed in thin section. Where quartz and feldspar overgrowths are present, chlorite and illite/smectite grain-rimming cements lie, at least partially, between the grain and the overgrowth, thus indicating that overgrowth formation postdated clay cementation. Feldspar overgrowths probably predate, or are in part contemporaneous with, quartz overgrowths in these shallow Frio samples, although direct textural evidence is lacking. However, other studies of Frio diagenesis inferred these same temporal relations (Lindquist, 1977; Bebout and others, 1978; Loucks and others, 1986). Dissolution of the least chemically stable framework grains and rock fragments (feldspars, VRFs) began with deeper burial and continued throughout the burial history of the Rincon reservoirs. There were probably discontinuous periods of enhanced dissolution (Fig. 29), perhaps coinciding with episodes of migrating pore fluids. Loss of detrital grains from sandstones represents one of the volumetrically most important diagenetic processes that has occurred and is occurring in the Frio Formation (Milliken, 1989). In the few heavily calcite-cemented samples examined, calcite cement fills voids that are one to several grain diameters in size and are a replacive component of partially leached framework grains, all evidence that calcite cementation followed significant grain dissolution in the Rincon reservoirs. However, most Rincon samples exhibit abundant porosity due to subsequent dissolution of most of the calcite cement, as indicated by characteristic residual patches of sparry cement with corroded edges. Where calcite-cement volume is low owing to dissolution and creation of porosity, sample porosity is higher. Calcite dissolution was a significant diagenetic stage that was magnified by the preceding and contemporaneous leaching of framework grains, particularly feldspars and VRFs. Sparse patchy kaolinite cement fills voids created by the loss of calcite cement. However, earlier kaolinite cementation is also inferred.

The petrology and ultimately the diagenesis of these Frio sandstones are primarily a function of source area and, secondarily, of original depositional environment. The presence of volcanic source terrains in northern Mexico and West Texas controlled the large volume of VRFs and feldspars in the Frio Rincon sandstones. Leaching of these abundant framework constituents created the porosity in which calcite cement precipitated and from which the cement was subsequently largely leached. Depositional environment had a secondary but important influence on porosity and permeability. Because of the fluvial depositional setting of the Rincon reservoir facies, these sands were poorly sorted and experienced minimal winnowing of the more chemically unstable and softer framework grains, such as plagioclase and VRFs. Therefore, high percentages of volcanic grains were preserved prior to burial and diagenesis.

Determination of Finest Scale Genetic Units

Correlation of bounding surfaces and reservoir genetic units

Subdivision of the Frio D and E reservoir interval consisted of defining correlation surfaces that are interpreted to represent a series of time slices through the reservoir zone. A primary goal in detailed reservoir characterization is to subdivide a productive reservoir interval so that any nonpermeable unit (usually mudstone) that may form a continuous barrier between two or more wells is associated with a bounding surface. In fluvial sandstone reservoirs, this objective is most often achieved by correlating mudstone units, representing primarily interchannel floodplain facies, from well to well. In many instances, floodplain mudstone units are not continuous across more than a few wells, and where equivalent mudstone is not preserved in adjacent wells, the position of a bounding surface must be defined within an interval of sandstone. Some of the mudstones used as correlation surfaces occur throughout the entire field study area. Most mudstones are more restricted in areal extent and occur over only a portion of the study window. Some were observed in only a few wells. Identifying the distribution of all shale barriers is very important, as they are probably the most significant cause of heterogeneity in fluvial reservoirs and are responsible for the isolation and compartmentalization of parts of the reservoir, thereby preventing adequate primary drainage and efficient sweep by injected fluids.

Ten primary correlation surfaces were used to subdivide the Frio D-E reservoir zone. There are eight productive sandstone-rich reservoir zones defined within these primary surfaces. The depth of each correlation surface was defined in every well so that each surface could be interpolated throughout the study area for use in the development of a reservoir model.

Sandstone Geometry and Depositional History

Frio E reservoir units

A series of maps were constructed on each of the Frio D and Frio E reservoir subunits using net-sandstone values based on shale volume calculations from SP logs for each well and depositional facies interpreted from electric log signature. Geologic data from mature Frio reservoirs in South Texas consist primarily of pre-1950 electric logs and very limited whole core. Thus, facies studies must rely heavily on stratigraphic correlations using only these older electric logs.

The Frio E reservoir zone includes strata from the F shale marker to the E shale marker (Fig. 30). The entire zone is composed of four, predominantly upward-fining units divided by three low-resistivity marker beds. Each unit between two shale markers represents a depositional parasequence that together makes up a larger-scale, backstepping, or retrogradational cycle that took place during deposition of the entire E zone.

The onset of sand deposition in the Frio E stratigraphic interval is represented by the E-4 unit (Fig. 31). Log facies and net-sandstone thickness patterns reveal the development of two to three discrete through-going fluvial channels oriented along directional dip from northwest to southeast. Individual log facies patterns of these channels exhibit blocky and upward-fining

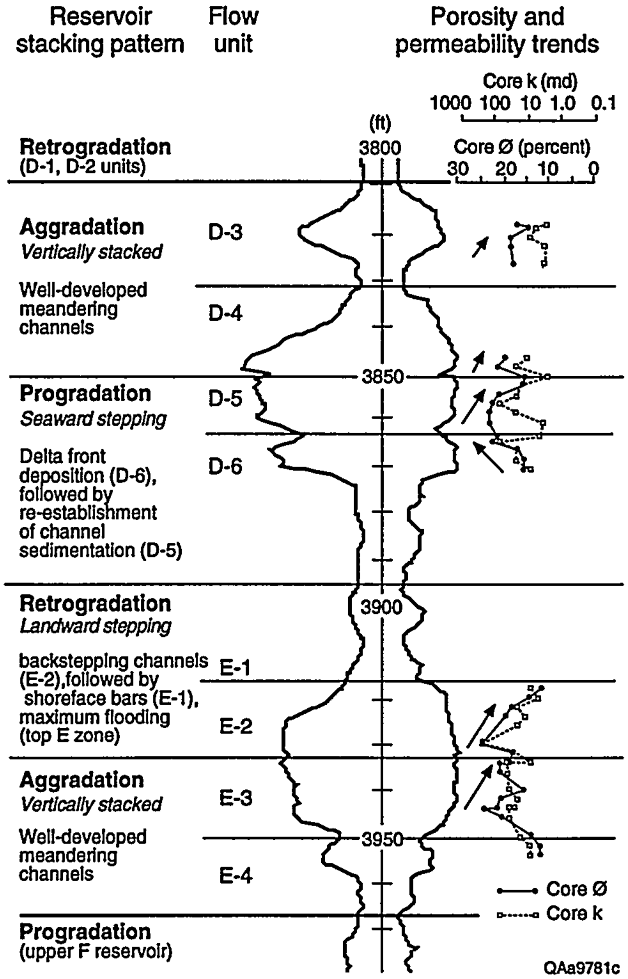
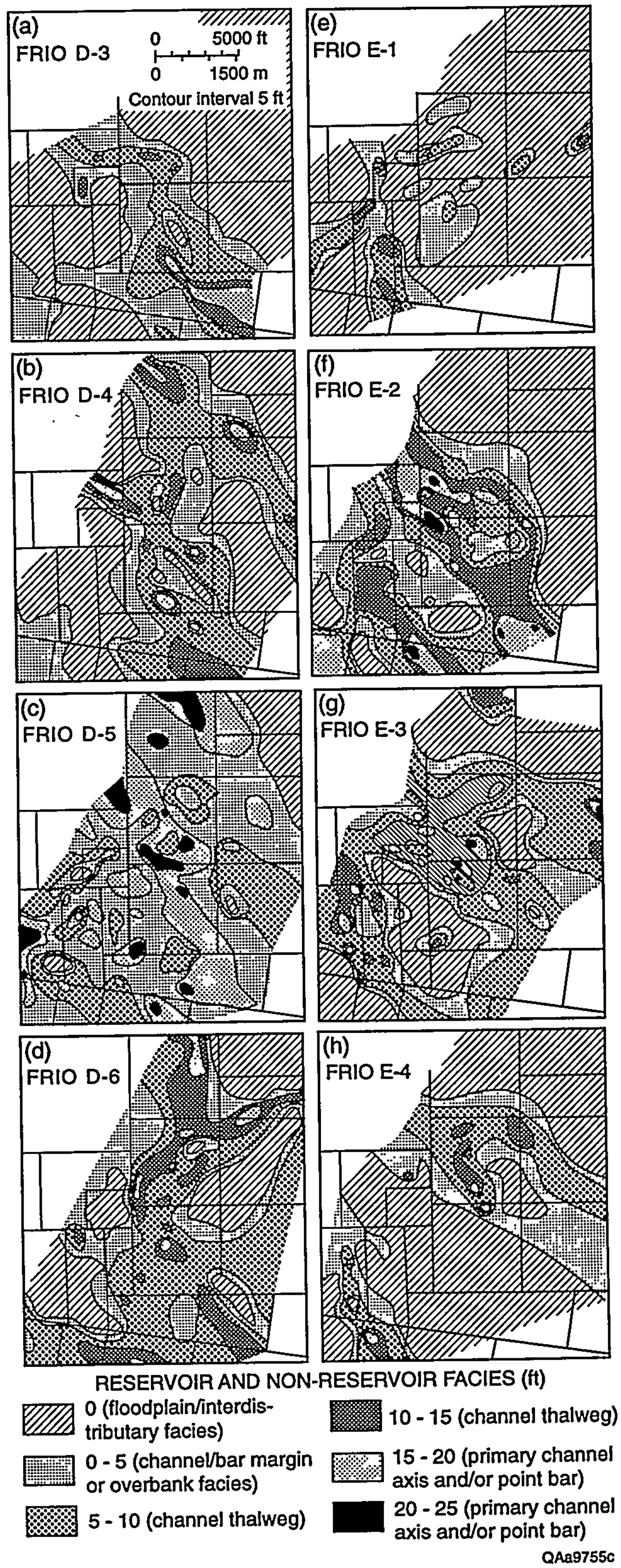


Figure 30. Representative SP/resistivity log illustrating succession of stacking patterns developed within the Frio E and D reservoir units. Conventional core analysis data posted on the right illustrate porosity and permeability trends commonly observed in each subunit that generally correspond to SP and resistivity bell and funnel curve shapes indicative of upward-fining channel sandstones and upward-coarsening bar sandstones, respectively.

responses representing channel-fill facies. The next depositional unit, the E-3 sandstone, is characterized by thicker development of sandstone, reflecting an increase of sediment supplied to this portion of the depositional system. The dip-elongate channel patterns observed in the underlying E-4 unit are still apparent. The channels are distinctly separated by floodplain facies in the downdip portion of the map area, but in the updip portion, the channels appear to be better connected, suggesting some flow-communication would be present between the two. Higher up section in the E-2 unit, dip-oriented NW to SE channel geometries still predominate. In the updip portions of these channels, some minor strike-oriented features are apparent, and maximum sand thicknesses have stacked up in a more updip position relative to earlier deposition, indicating a backstepping pattern caused perhaps by relative sea-level rise.

Figure 31. Series of net sandstone isopach and facies maps showing changes in the distribution of facies and sandstone facies geometry for the Frio E-4, E-3, E-2, and E-1 reservoir units and Frio D-6, D-5, D-4, and D-3 reservoir units.



A significant change in the amount and distribution of sandstone is observed at the top of the E-zone. In the E-1 unit, mudstone facies predominate, and the majority of sandstone is distributed in strike-oriented bodies that are limited in areal extent. These small strike-oriented sandstone deposits are interpreted to represent the development of minor shoreface bars associated with continued backstepping or retrogradation. A narrow dip-elongate channel, perhaps a narrow tidal channel, is present in the far southwestern corner (bottom left) of the map area. The advance of a laterally extensive flooding surface marks the end of E zone deposition.

Frio D reservoir units

The productive D reservoir interval also consists of four discrete depositional parasequences divided by three low-resistivity shales (Fig. 30). These are identified as the D-3, D-4, D-5, and D-6 units, and together they form a larger-scale depositional sequence that includes both progradational and aggradational units. Located above the E flooding surface, the D-6 unit is the lowermost sandstone of the D reservoir zone, and follows a relatively extended period of predominantly mud deposition. The strike-elongate sandstone pattern in the D-6 unit is believed to reflect initial progradation and development of a thin delta front. Upward-coarsening and blocky log responses in many of the electric log profiles of D-6 units are further evidence that delta-front sand facies make up this strike-oriented sand body. Dip-elongate channel deposition appears to be present in the northern portion of the study area, as well as across the center of the map where the strike elongate delta front sandstone is dissected by narrow upward-fining channel facies.

Progradation continues during deposition of the D-5 unit. The overall sandstone geometry in the D-5 consists of northwest-southeast trending, dip-parallel channel facies (Fig. 31). Because of the greater thicknesses of mapped sand patterns, it is difficult to distinguish boundaries between individual channels. The thickest development of sandstone is present as a relatively narrow channel feature that runs from northwest to southeast across the study area. The D-5 zone also contains evidence of some reworked strike-oriented delta front remnants, and log correlation in some areas indicates this unit may be mapped as two discrete episodes of channel deposition.

The uppermost Frio D reservoir subunits represent a return to more discrete channels and aggradational sedimentation. Both the D-4 and D-3 units are dominated by dip-elongate fluvial channel deposition. Sediment load being carried by these channels appears to be reduced from earlier D-5 deposition, as evidenced by thinner development of sandstone and more clearly identified channel margins. The two channel systems mapped in the D-4 unit appear to be in communication in the updip portion of the map area. The D-3 unit consists of a single, relatively broad channel system. In addition to the blocky and upward-fining log patterns that characterize channel-fill facies, serrate and thin upward-coarsening responses diagnostic of levee and crevasse splay facies are also observed adjacent to channel margins in these two units.

Establish Fluid-Flow Trends in the Reservoir

Initial Fluid Properties

Oil produced from the Rincon field is a light high-shrinkage crude. Oil gravity ranges from 40° to 48° API and formation volume factor ranges from 1.14 to 2.05 (STB/bbl). The high gravity gives the oil a favorable mobility ratio. The oil is associated with a gas cap; therefore, the oil was initially at bubble point pressure. This fluid character makes pressure maintenance important because any pressure drop causes gas to come out of solution.

Field Production History

Frio and Vicksburg reservoirs have produced more than 65 MMbbl of oil under combined natural water drive and gas cap expansion since discovery of Rincon field 55 years ago in 1939. Frio production peaked in 1944, when production averaged approximately 7,300 bbl/d. Vicksburg production began in 1950. Production from 38 separate Frio reservoirs has yielded over 45 MMbbl of oil.

Three main Frio reservoirs, the D, E, and G sandstone units, account for 69 percent of all completions and 88 percent of the oil produced in the field area selected for study (McRae and others, 1994). Most of the Frio oil reservoirs had initial gas caps, and reservoirs have produced under a combined natural water drive and gas cap expansion. Gas injection took place during the early years of field production in order to maintain reservoir pressure and extend the flowing life of the wells. Waterfloods performed in each of these large reservoir zones met with varying degrees of success. Oil production from these major reservoirs has declined steadily since 1968 and has been accompanied by increasing abandonments of individual reservoir zones. As of 1990, there were only 27 oil wells remaining in the field that were producing or had shut-in status, and average daily rates had declined to 373 bbl of oil and 4,576 Mcf of gas.

The Frio E sandstone is the most prolific reservoir zone in the field and has produced nearly 12 MMSTB of oil since production began in 1940. The E zones are individually mapped as the E-1, E-2, E-3, and E-4 sands. Stratigraphic correlation and production data from the operator indicate that the E-1 and E-2 sands are commonly in fluid communication, as are the E-3 and E-4 sand zones. Secondary waterflooding in the Frio E reservoir zone accounted for 2.5 MMSTB, or nearly 21 percent of total E zone production. An overall recovery efficiency of 38 percent was calculated for the combined E zone using average reservoir values of 26.5 percent porosity and 37.5 percent water saturation.

Frio D reservoirs have produced nearly 10 MMSTB oil since 1940. The main productive D sand interval consists of four units correlated as the D-3, D-4, D-5, and D-6 sands. These units are correlated as individual sandstones that combine into a complex stratigraphic channel system that covers more than 2,000 acres in the northern half of the field. Frio D sandstones have similar reservoir attributes as Frio E reservoirs (average porosity of 25.2 percent, Sw of 40.5 percent, and estimated OOIP of approximately 35 MMSTB) but a lower recovery efficiency of 29 percent. Waterflooding attempts in this reservoir zone accounted for secondary recovery amounting to only 2 percent of total D production. These disappointing results were attributed by the field operator to the heterogeneous nature of the D sandstone interval.

Evaluation of Areal Trends of Past Oil Production

Areal patterns of reservoir development identified by isoproduction contours reveal the general distribution of hydrocarbon storage capacity and degree of flow communication within a productive reservoir zone. These maps also may indicate areas where there are significant production contrasts that may be a direct result of flow barriers created by stratigraphic heterogeneity. In many cases well completions in a given reservoir include a stratigraphic interval that spans more than one flow unit, and in these situations, cumulative production data on a per-well basis provide less insight into the stratigraphic distribution of production in an individual flow unit. However, such data can provide general insights into the production behavior of the selected reservoir.

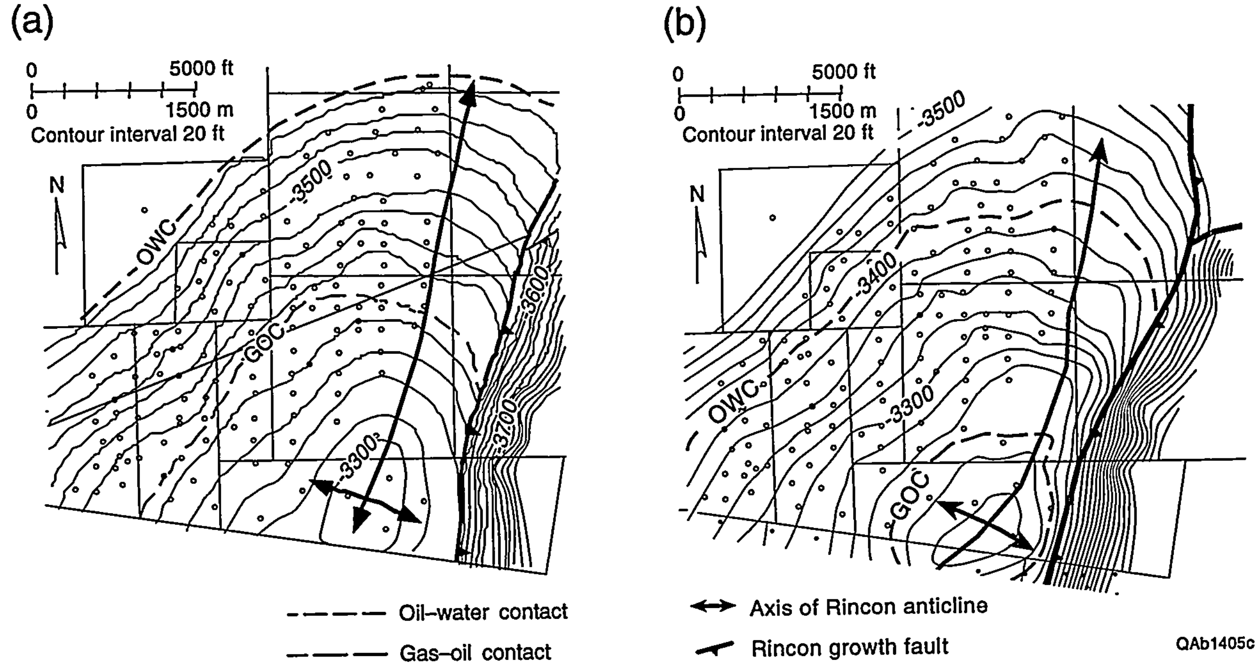


Figure 32. Comparison maps illustrating differences in overall reservoir geometry and distribution of production, Frio D and E reservoir zones. Maps on the left for the Frio E reservoir show (a) representative structure contoured on the top of the Frio E unit, showing the anticlinal pattern of the Rincon structure and location of the down-to-the-east Rincon growth fault; and (c) cumulative oil production for the combined Frio E reservoir; and (e) isopach map from the total E sandstone reservoir zone, showing distribution of net sandstone thickness and depositional geometry. The stacking of greater sandstone thicknesses in the updip portion of map area may have created increased flow communication between adjacent channels along the crest of the structure and caused the relatively high recovery efficiency of the E reservoir. Maps illustrating structure (b), distribution of cumulative oil production (d), and total net sandstone thickness (f) are presented on the right for the Frio D reservoir. In contrast to the Frio E zone, the strong dip-elongate depositional pattern and narrower geometry of Frio D channels make this reservoir appear more compartmentalized and may explain lower overall recovery efficiency.

In the Rincon field, where production from many completions was commingled, structural maps (Fig. 32 a,b) and cumulative production isopach maps (Fig. 32c,d) were constructed for both the Frio D and E reservoir zones to help identify the general distribution of oil production. Composite net sandstone thicknesses were calculated over the total Frio D and total Frio E reservoirs to serve as a comparison to the total reservoir production maps (Fig. 32e,f). The cumulative production map for the E reservoir shown in Figure 32c illustrates the trend of high

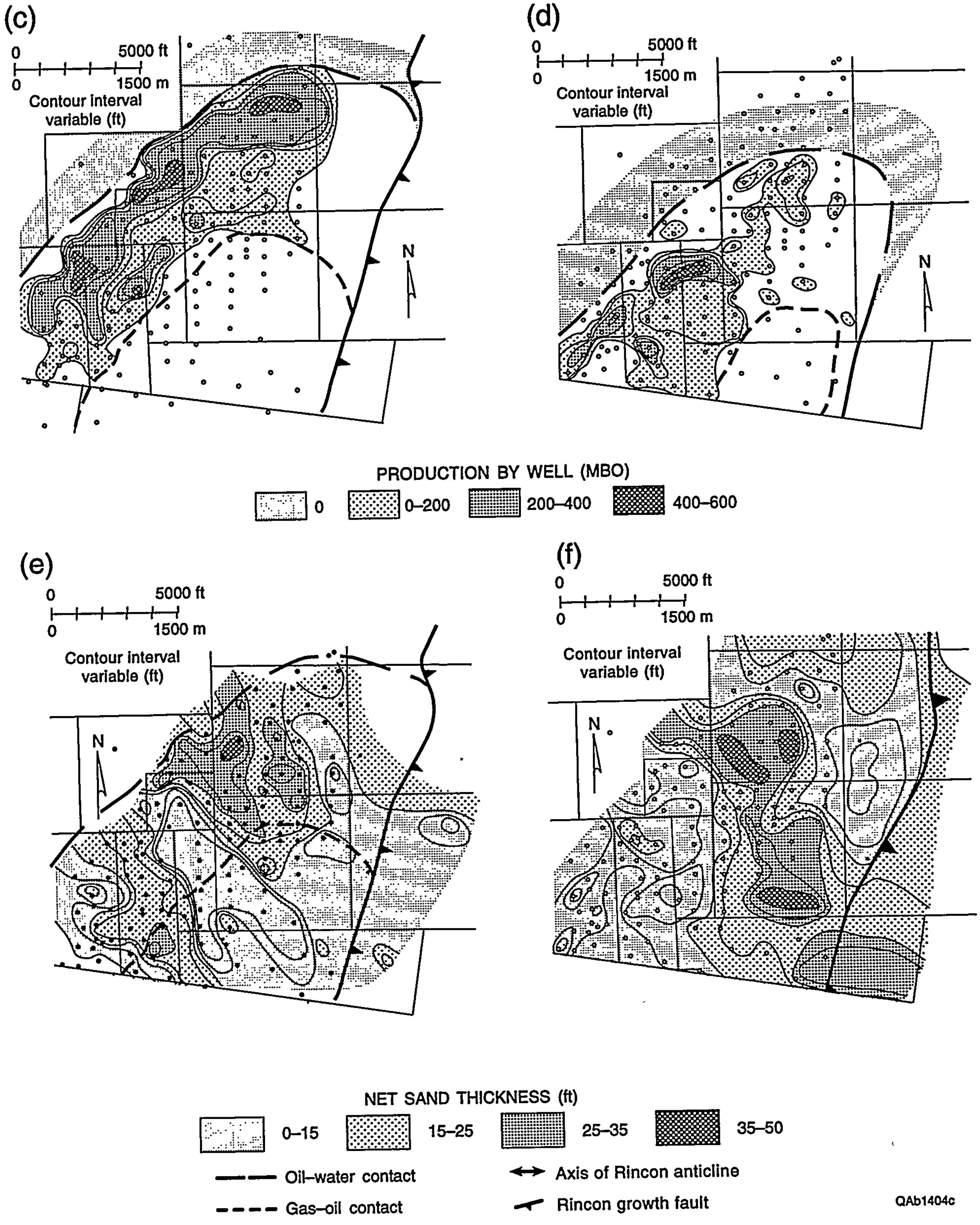


Figure 32 (cont.)

production following along the lower edge of the structure. The correspondence between better production and the downdip edge of the reservoir is due to efficient water drive in the lower portions of the reservoir. In addition to structural position, another control on cumulative production appears to be differences in net thickness. The composite E reservoir net sandstone isopach map shows greatest sand thicknesses occurring in the updip portion of channels, and comparison with the production map indicates that higher production approximately corresponds to areas of thicker net sandstone that generally follow along channel depositional axes (Fig. 32e).

Maps comparing the distribution of oil production in the D zone with structure show a similar pattern as was observed in the E reservoir zone, with production "hot spots" oriented along strike parallel to the crest of the anticlinal structure (Fig. 32d). Areas of high production within the D reservoir appear to be much more isolated than was observed on the E cumulative production map (Fig. 32f). The total net sandstone thickness map for the combined D interval shown in Figure 32e illustrates the strongly dip-oriented pattern of the composite D sandstone interval. The stratigraphic complexity of this interval of vertically stacked and laterally coalescing sandstone lobes provides ideal conditions for isolation of oil accumulations in multiple reservoir compartments, many of which may be incompletely drained or completely untapped.

Integrating Fluid-Flow Trends in the Reservoir

Identifying Correspondence Between Stratigraphy, Structure, and Fluid-Flow Trends

Effect of Sandstone Geometry on Oil Production

The Frio D and E reservoir intervals illustrate a systematic evolution of sediment transport styles and stratigraphic stacking patterns (Fig. 30). These are: (1) aggradation in the lower Frio E-4 and E-3 reservoir units, (2) retrogradation in the upper Frio E-2 and E-1 units, (3) progradation in the lower Frio D-6 and D-5 units, and (4) a return to aggradation in the Frio D-4 and D-3 units. These different styles of deposition directly affect the reservoir geometry present within each sandstone unit (Fig. 31). Aggradational and progradational channel sedimentation create dip-oriented channel sandstones that may or may not be in communication with each other. Strong dip-oriented geometry in the D units and the development of successively more laterally isolated channels during aggradation reduces communication between units that may be directly responsible for lower recovery efficiency. Retrogradational units such as those present in the E reservoir, in contrast, allow reworking of previously deposited sediment into long strike-oriented features that have potential for increased flow communication. Evaluation of individual map patterns suggests that the strike-oriented distribution of sandstone located in the updip portions of the map area in the E-3 and E-2 units, combined with the relative broadness (3,500–7,000 ft) and lower sinuosity of individual channel units, may lead to greater interconnectedness of channels and increased communication between reservoir flow units. The updip stacking of sandstone thickness and lateral connectivity between E units may be controlling factors in the relatively high recovery efficiency (38 percent) of this reservoir zone.

Matching Stratigraphy with Reservoir Production

Reservoir development patterns within the Frio E reservoir

Reservoir development within each unit was indicated by identifying wells with completions within that particular stratigraphic unit. In addition, wells were identified that were not perforated within the mapped zone but were completed in a reservoir subunit stratigraphically above or below the mapped unit that may have been in partial or complete vertical communication. The series of reservoir geometry/development maps prepared for the E reservoir units are shown in Figures 33 through 36.

The Frio E-4 unit has the least number of completions of the three E reservoir units (E-4, E-3, and E-2) that are characterized predominantly by channel sedimentation. This unit consists of two discrete dip-oriented channel bodies that are separated laterally by at least 3,000 ft of non-reservoir floodplain facies (Fig. 33). The channel located in the southwest portion of the map area is narrow (1,000–1,500 ft) and contains a relatively thin channel margin facies as interpreted from

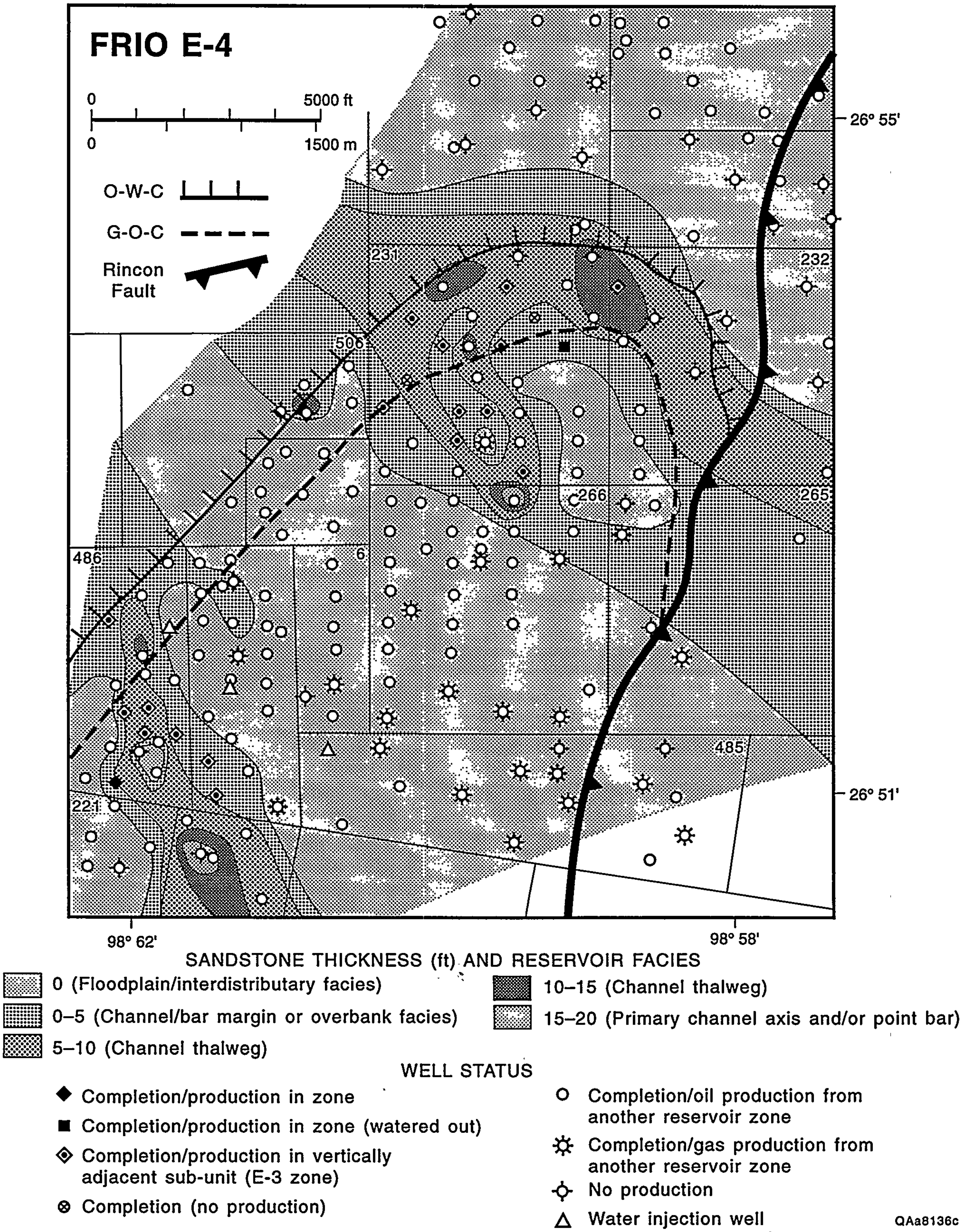


Figure 33. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio E-4 reservoir unit.

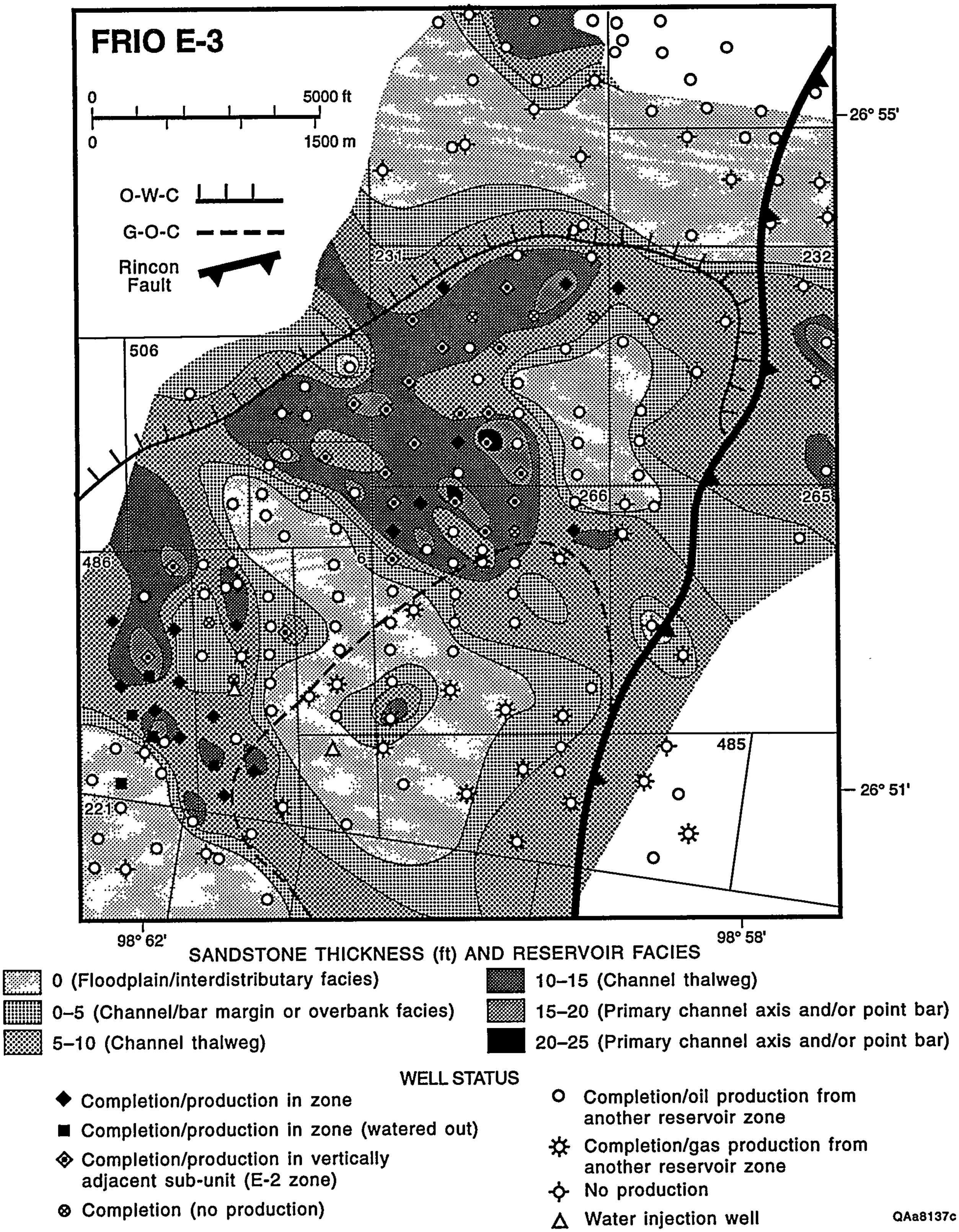


Figure 34. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio E-3 reservoir unit.

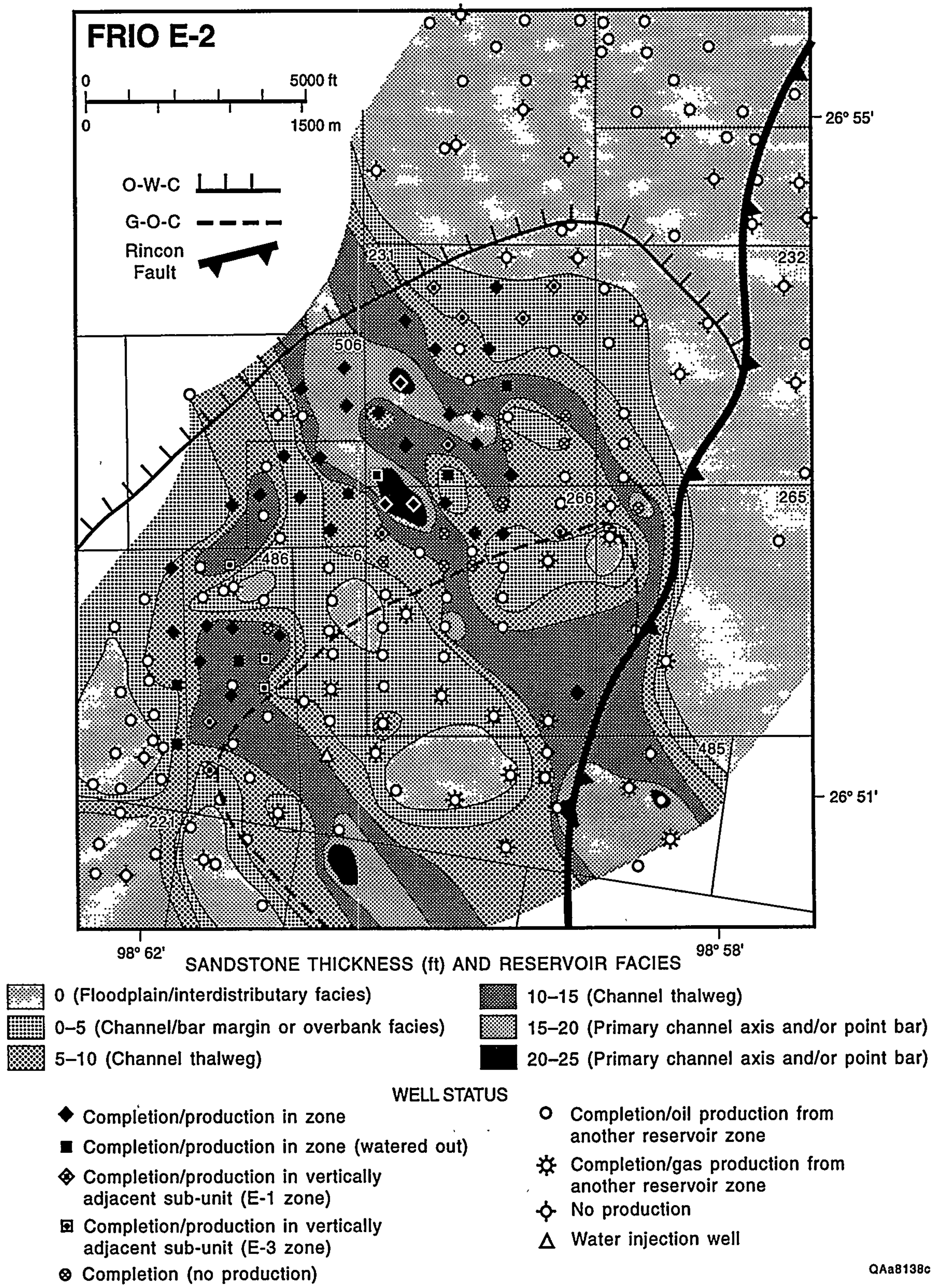


Figure 35. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio E-2 reservoir unit.

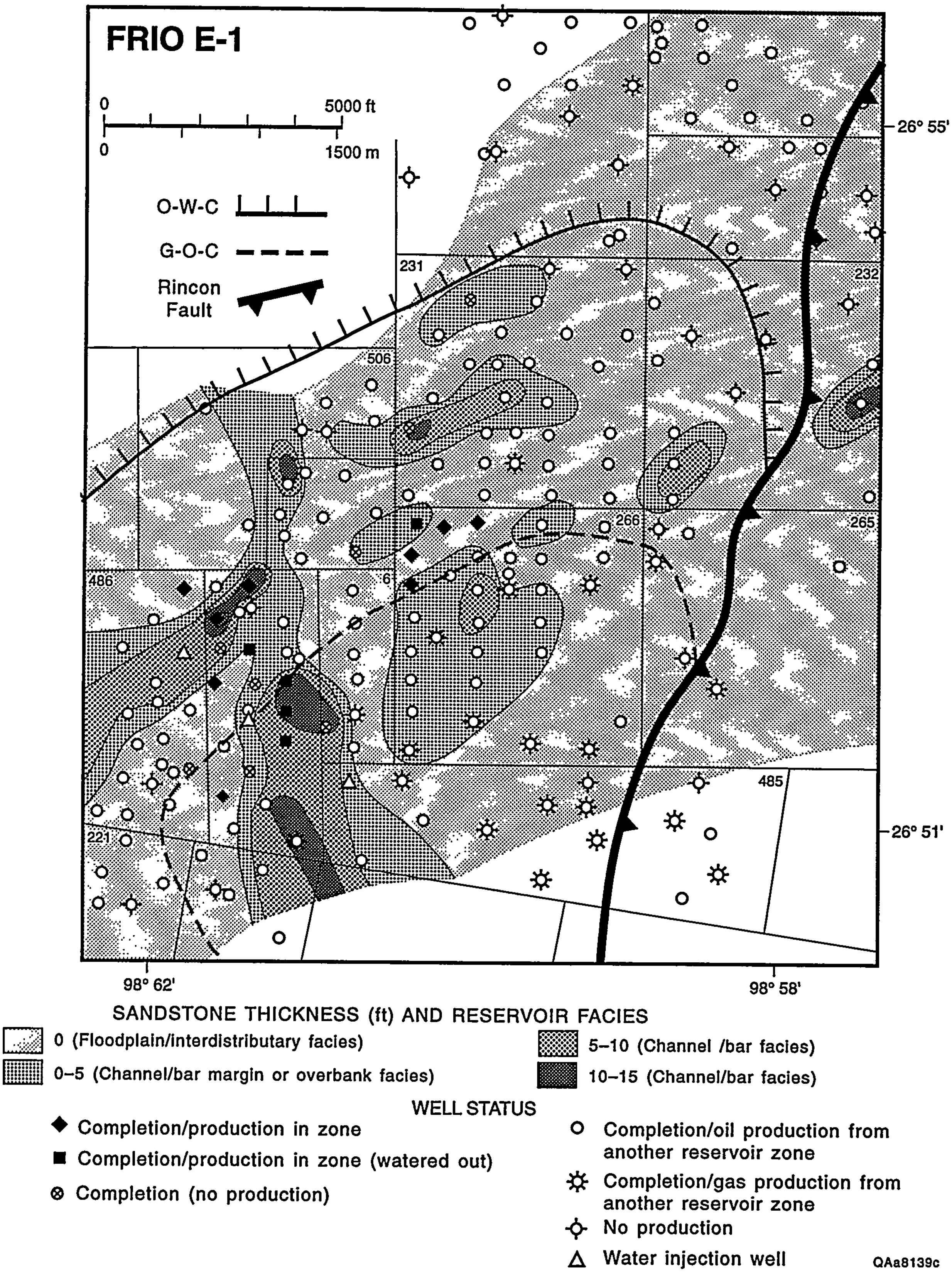


Figure 36. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio E-1 reservoir unit.

net sandstone isopachs. The channel system located in the central portion of the map area consists of two main channel tracts defined by thicker development of sandstone, and these are probably in flow communication. The updip, connected portion of this channel system is approximately 3,500 ft wide and narrows to 2,000–2,500 ft farther downdip, where it appears to bifurcate into two separate channel units. Forty-nine wells penetrate sandstone facies in the E-4 reservoir, and only 21 of these have been completed. Many of these completed wells may have associated production, but actual volumes are not known because all E-4 production reported by the operator was assigned to the combined E-3 & E-4 reservoir zone.

E-3 unit reservoirs appear to consist of three separate channel systems oriented northwest to southeast across the field study area (Fig. 34). The location of the oil-water contact indicates that it is likely that the southwesternmost channel is not in communication with the two channels located to the north. The two northern channels appear connected, in part, and are probably in lateral communication. The southwestern channel is approximately 2,500 ft wide and has 50 completions and 21 producing wells. The majority of completions and producing wells are located in the two northern channels. Many additional wells have been completed in a vertically subjacent zone, primarily the overlying E-2 reservoir, and have produced oil, some of which may be properly allocated to the E-3 unit. More than 3 MMBO of production has currently been assigned to the E-3 reservoir.

The Frio E-2 reservoir unit possesses the greatest number of completions (64) and producing wells (46) of all the E reservoir subunits. The mapped sandstone geometry (Fig. 35) shows two primary dip-oriented channels that are probably only in partial communication because of the floodplain facies and lower permeability channel-margin facies developed between the two channel areas. The primary channel area in the E-2 unit is relatively broad (4,000–6,000 ft) and contains sandstone facies that have some of the highest permeability values (1250 md+) measured in the field. Present production allocation indicates that the E-2 unit is also by far the most prolific oil reservoir in Rincon field, with more than 7.5 MMBO currently reported.

The uppermost E reservoir sand, the E-1 unit, has the fewest completions of all E subunits. Part of this is attributable to the fact that the E-1 and E-2 sandstones were developed as though they were usually in flow communication, and extensive development in the E-2 reservoir has likely produced much of the E-1 oil. Sandstone isopach mapping and evaluation of log facies in this study suggests that the E-1 sandstone was deposited in a retrogradational cycle where pre-existing channel units have been eroded and reworked into a series of strike-elongate bar sandstones that cover most of the mapped study area (Fig. 36). Well data and log facies interpretations indicate that these bar units are thin (mean thickness of 6 ft) and not very laterally continuous (width dimensions from 1,500 to 3,000 ft). This facies interpretation indicates that there may be less vertical communication between E-2 and E-1 reservoir units than previously assumed.

Reservoir development patterns within the Frio D reservoir

Composite maps illustrating the distribution of reservoir sandstone, facies patterns, and level of development for each of the D reservoir subunits are presented in Figures 37 through 40. As discussed previously, the lowermost D reservoir unit, the D-6 sand, has been interpreted to represent part of a progradational cycle of sedimentation during which strike-elongate sandstone bars deposited during the previous retrogradational cycle are being eroded and transected by a dip-oriented channel system that trends across the center of the map area (Fig. 37). Upward-coarsening profiles observed on electric logs indicate the presence and northeast-to-southwest distribution of the bar sandstone facies that appears to be in the process of being dissected by the northwest-to-southeast oriented channel. The D-6 unit has relatively few completions (14), and although some of these completions were productive, all production was originally assigned to the composite D-5 reservoir zone.

As illustrated in Figure 38, the depositional geometry of the Frio D-5 subunit is very complex. The isopach map pattern reveals the presence of a primary axis of deposition, indicated by the thickest development of sandstone, running from northwest to southeast across the center of the map area. The relatively thick sandstone throughout this reservoir zone obscures much of the depositional pattern. The D-5 zone has more completions (60) and productive wells (39) than

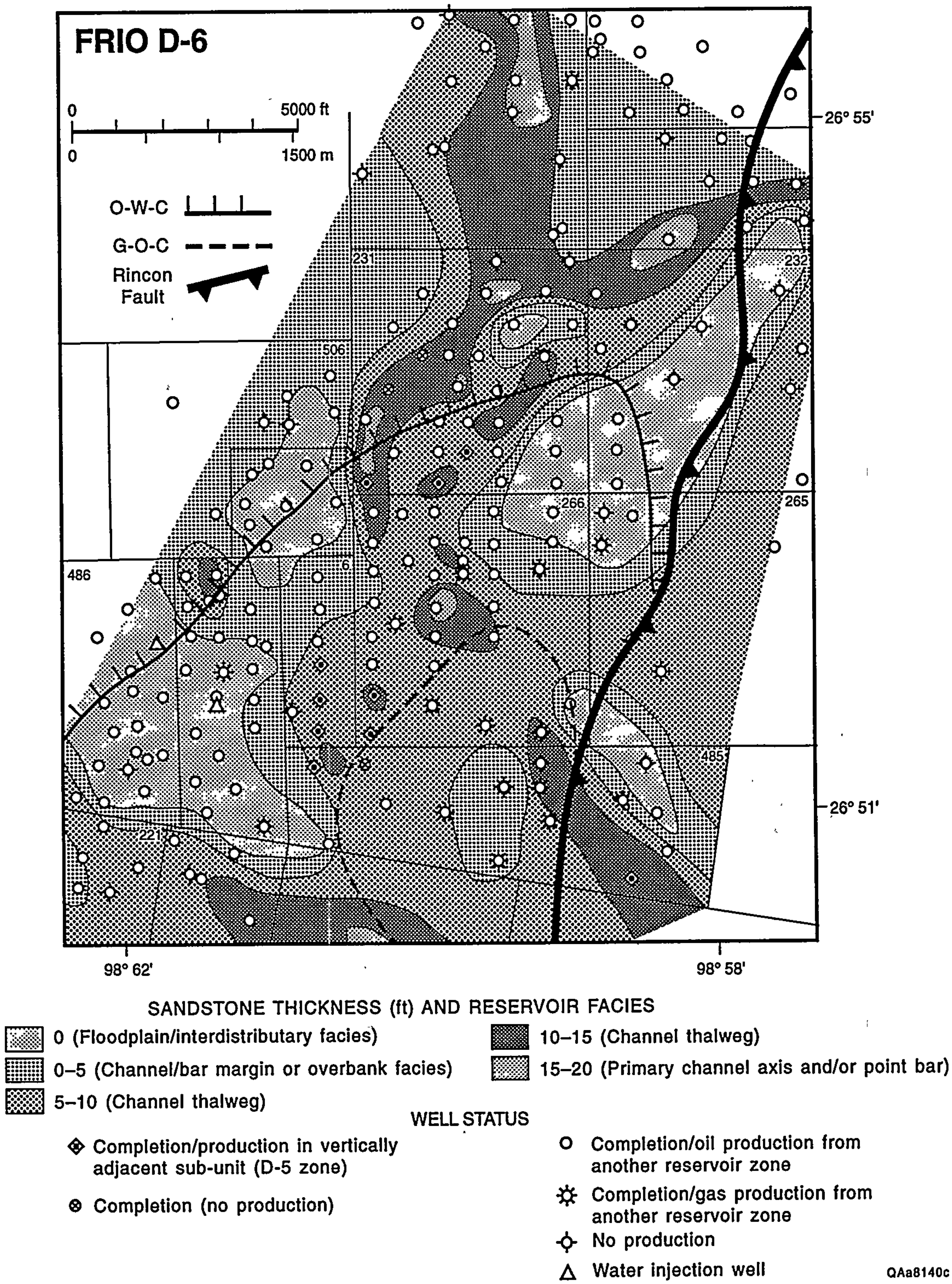


Figure 37. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio D-6 reservoir unit.

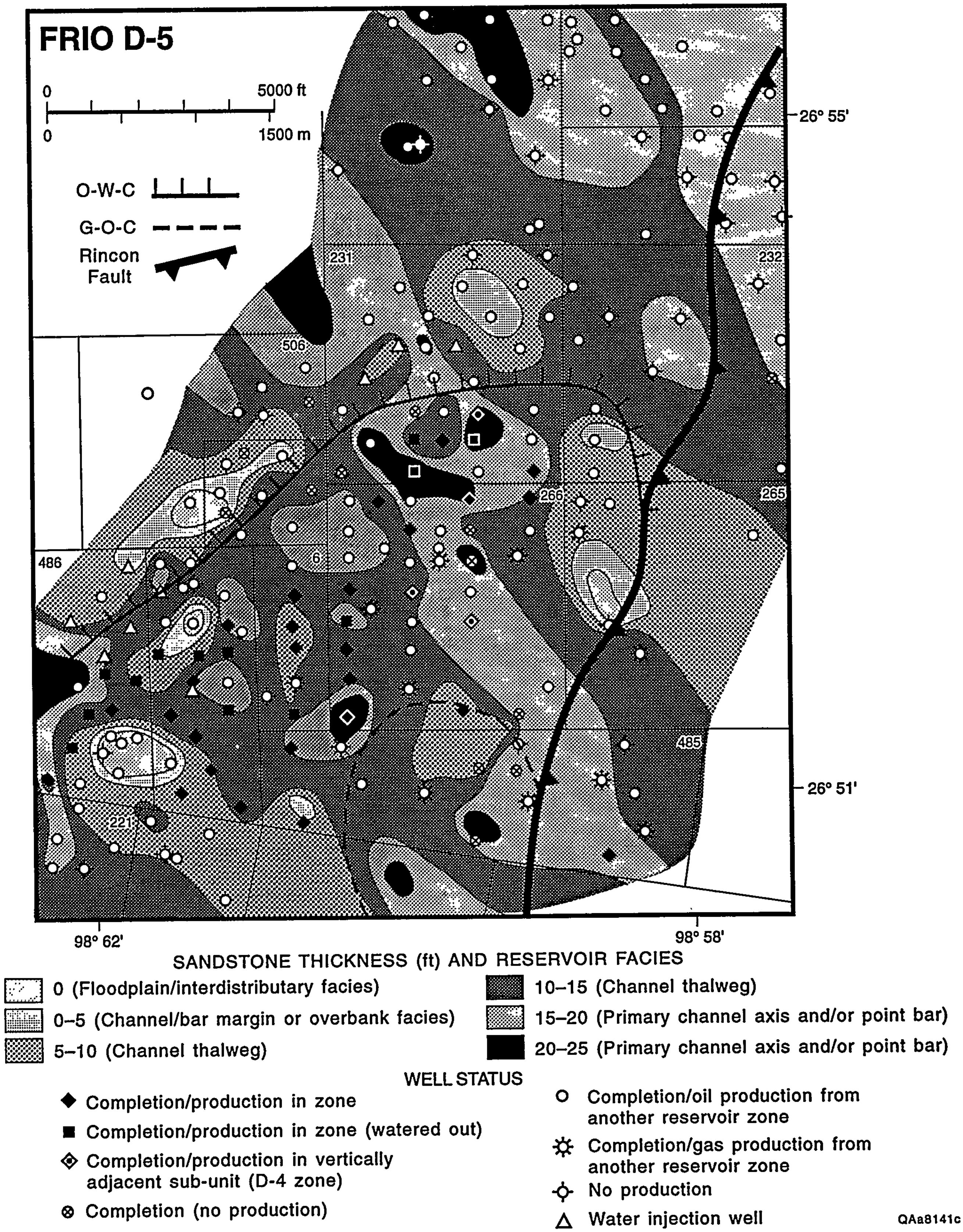


Figure 38. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio D-5 reservoir unit.

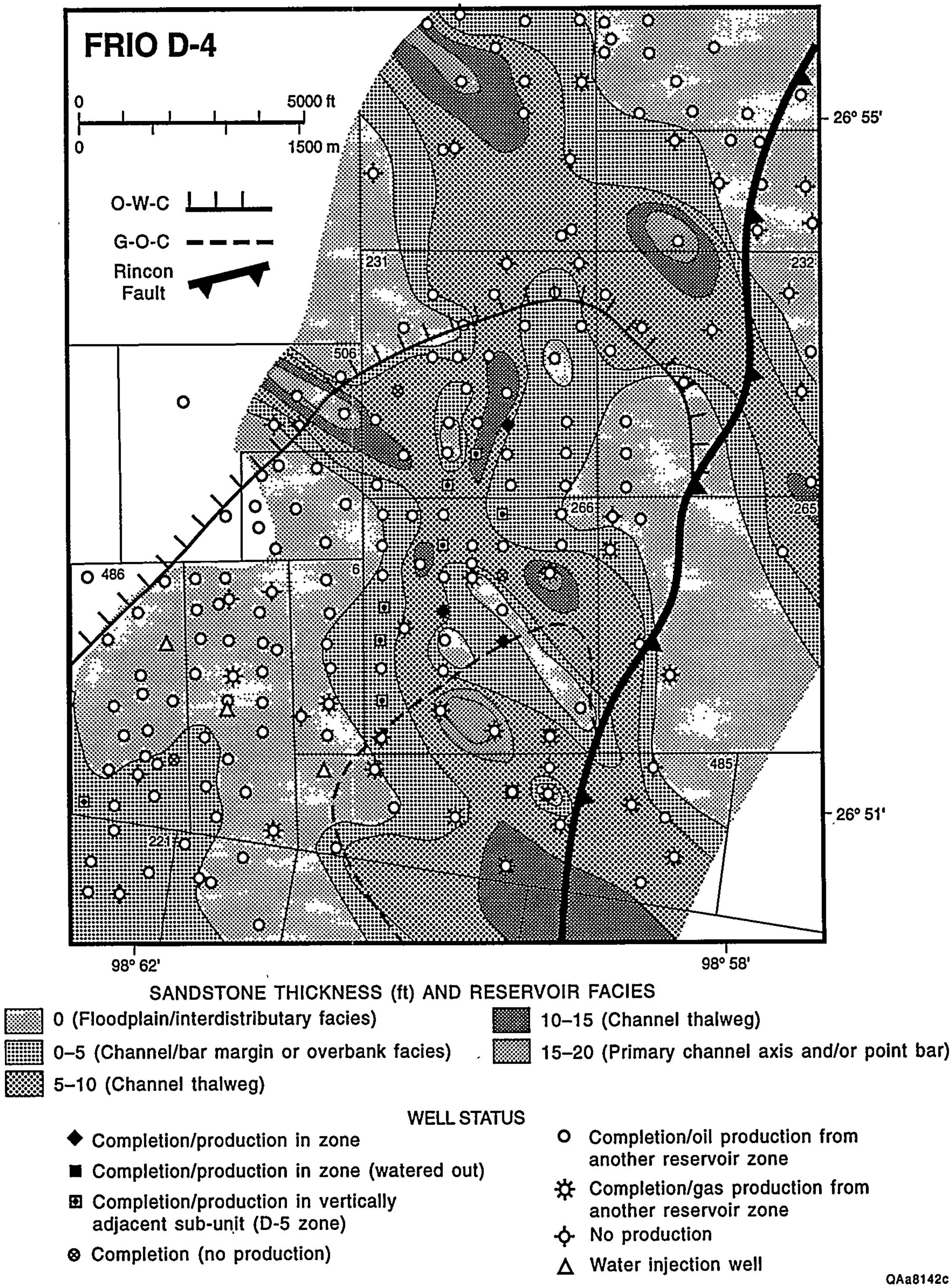


Figure 39. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio D-4 reservoir unit.

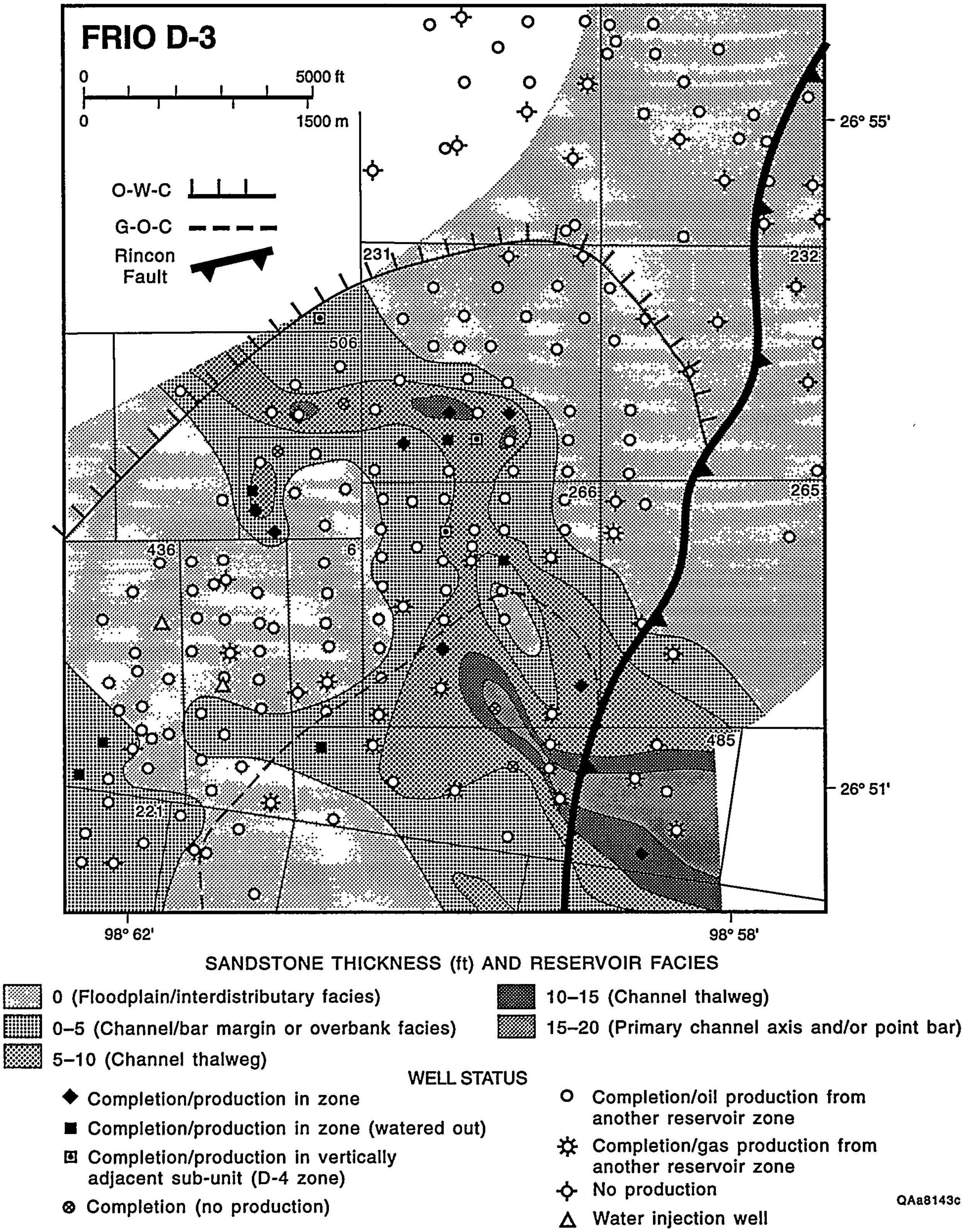


Figure 40. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio D-3 reservoir unit.

all other D reservoir units combined, and production reported for the composite D-4, 5, 6 reservoir zone totals in excess of 6 MMBO. Assessment of the permeability distribution within the D-5 unit suggests that there are several areas where flow baffles or barriers may exist, and this heterogeneous unit probably represents the best potential for identifying incompletely drained or completely undeveloped reservoir compartments.

The D-4 reservoir unit consists of a series of two to three dip-oriented channel units that appear to be connected in their updip portion of the map area, and they therefore are likely in lateral communication with each other (Fig. 39). Channel boundaries are clearly defined and width dimensions range from 2,000 to 3,500 ft. The number of completions within the D-4 unit (16) is few compared to those in the D-5. Vertical communication between D-4 and D-5 sandstones is probable, and it is assumed that many D-5 completions have also produced oil from the D-4 unit.

Reservoir geometry in the D-3 unit is also clearly defined, and is mapped as a single channel that transects across the center of the field area (Fig. 40). The channel dimensions are relatively narrow in the updip region (2,500 ft) but broaden significantly downdip to the southeast to more than 6000 ft wide. The D-3 unit has reported production from 10 wells of nearly 750 MBO, but some production associated with 12 additional completions has been assigned to the D-5 composite reservoir zone in wells where D-3, 4, and 5 units have been considered to be in communication.

Reservoir Petrophysical Model Development

Porosity and Permeability Modeling

Accurate characterization of porosity and permeability and their distribution within a hydrocarbon reservoir is the key to understanding past production history and is of obvious importance in designing future incremental recovery strategies to maximize resource development. Because they can be directly related to fluid transmissivity and therefore productivity, permeability values can provide a direct means to allocate total hydrocarbon production to specific geologic units. In many older reservoirs, such as in Rincon field, production has been combined and reported for multiple sandstone units, and characterizing the vertical permeability distribution within wells and lateral distribution of permeability between wells is possible only when abundant data from routine core analyses are available. Rincon field is unusual among mature South Texas oil fields in its abundance of core data. The field was extensively cored during its early drilling phase, and although these wireline cores were not preserved, core analysis data exist from more than 100 wells within the general field study area.

The standard technique used by many operators for estimating porosity and permeability is to combine all routine core data from a reservoir to derive a general porosity/permeability relationship, and then use this derived relationship along with porosities calculated from well logs to estimate permeability in uncored wells and intervals. This method is obviously inappropriate in heterogeneous reservoirs. The use of a single relationship between porosity and permeability may result in underestimating the possible permeability contrasts present within a reservoir interval, and this will subsequently lead to incorrect calculations of original-oil-in-place volumes and inaccurate predictions of future production potential.

Porosity and permeability distribution for primary facies types

Measured porosity and permeability values from wireline cores were analyzed with their sample depths and corresponding reservoir subunit and facies types identified from patterns on sandstone isopach maps and electric log signatures, respectively. Evaluation of log facies and sandstone distribution for each of the reservoir subunits reveals three primary depositional facies types: (1) channel (dip-elongate) sandstone reservoir units, (2) bar (strike-oriented) sandstone reservoir units, and (3) overbank (levee and crevasse splay) units. Basic descriptive statistics, including histograms and linear regressions of porosity versus permeability, were calculated for each different subgroup of data. Frequency distributions of core porosity and permeability values grouped according to the three general facies types are illustrated in Figure 41. Channel units, on average, possess higher values of porosity and permeability (21% mean f, 61 md mean k) than the

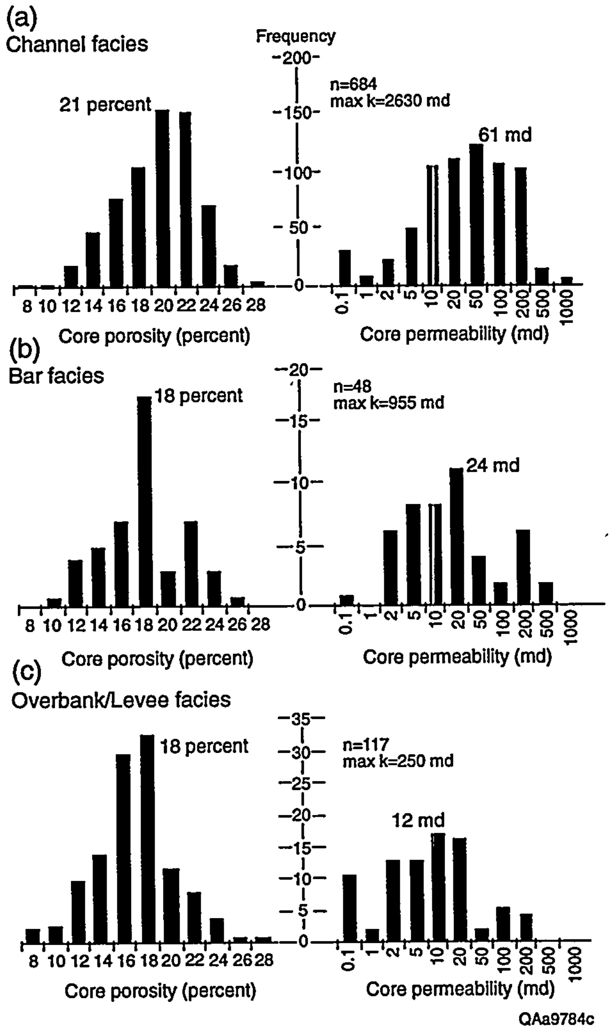


Figure 41. Histograms illustrating the distribution of porosity and permeability values according to each of the mapped reservoir facies: (a) aggradational channels, (b) retrogradational bars, and (c) overbank (splay and levee) facies.

bar sandstone units (mean f of 18%, mean k of 24 md). Overbank facies have lower porosities (mean 18%) and substantially lower permeabilities (mean 12 md) than either channel or bar sandstones. Mean permeability values for thin upward-coarsening log patterns interpreted to be crevasse-splays are 25 md (range 0.3–199 md) and are 5 md (range 0.1–54 md) in units with serrate log responses classified as levee facies. These poorer quality overbank facies generally are not significant reservoirs.

The porosity-permeability relationship between facies is distinctly different. Porosity and permeability for bar sandstone facies in the E-1 and D-6 reservoir subunits and for all fluvial facies types in the other reservoir units were cross plotted, and a nonlinear regression was performed for each group. The resulting equations for the regression lines demonstrate the

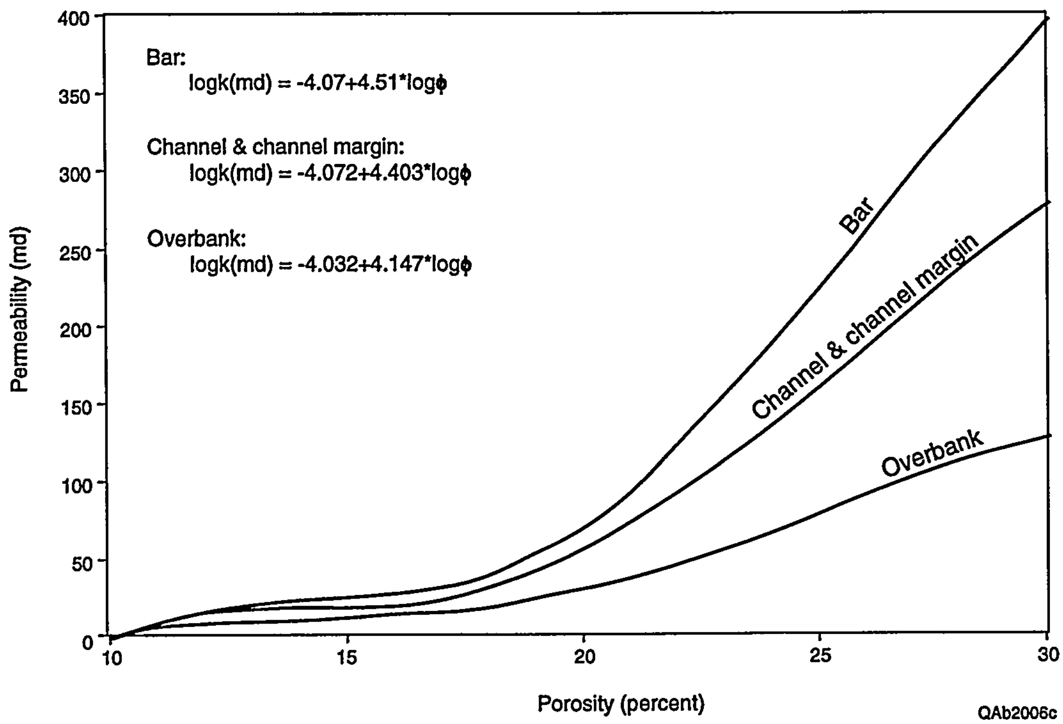


Figure 42. Nonlinear regression analysis on a facies-by-facies scale results in an equation to predict permeability from porosity.

different porosity-permeability relationships between these facies types. Similar porosity values have the lowest corresponding permeability for overbank facies, midrange for channel sandstone facies, and the highest for bar sandstone facies (Fig. 42). Therefore, greater accuracy in permeability estimation can be achieved by calculating permeability on a facies-by-facies scale.

Well log analysis

Petrophysical analysis of the Frio D and E reservoirs in Rincon field includes (1) integrating core data with geophysical log data, (2) quantifying petrophysical properties from wireline logs, and (3) testing the validity of these derived properties by comparing maps of log facies and net sandstone thickness with reservoir-volumetrics maps. The development of petrophysical models to calculate porosity, permeability, and water saturation from geophysical log data is based on thorough evaluation of wireline core analysis data, results from special core analyses, petrographic identification of the type and distribution of clay minerals, and calculated shale volumes of reservoir units. The lack of porosity log data in the field (only six wells have porosity logs) requires petrophysical characterization of porosity to be based primarily on indirect methods using non-porosity logs such as SP and resistivity.

An example of core and porosity log data over the E reservoir in the T. B. Slick A149 well is shown in Figure 43. This is one of two wells for which we have whole core, abundant conventional core analyses, and a modern log suite including gamma-ray, deep induction, density, and compensated neutron log curves. There is no spontaneous potential log for this well, and this is most unfortunate, because virtually all of the other wells in the field have SP logs (and no gamma ray), and therefore no whole core-SP log calibration can be made. Comparisons of the resistivity curve (1) with the core graphic log (2) and with porosity (3) and permeability (4) data measured on core samples show a reasonable correlation between resistivity, core facies, and porosity and permeability. Sandstones with reduced porosity and permeability correspond to locations described in core as basal channel facies, or they are carbonate cemented. These permeability variations are not readily recognizable from the log data alone.

Relationships between log resistivity and porosity were studied in order to develop a model to determine porosity from electric log data. Relationships determined for porosity and resistivity were subsequently used to calculate permeability using the appropriate porosity/ permeability relationship that has been identified for each reservoir facies type.

Analysis of modern logs

Modern well logs are uncommon in Rincon field, but it is important to develop a methodology so that new development and reexploration can be analyzed. A log suite in well 149, including gamma ray, resistivity, density and compensated neutron porosity, as well as core data, was analyzed in order to develop a strategy for wireline petrophysics.

The work-flow scheme for analyzing modern logs includes depth shifting core data to wireline depths, determining a bulk shale volume indicator (Vsh), and developing a porosity algorithm. Based on correlation with other wells, and the significant presence of radioactive lithic fragments within the sandstone, it is determined that the gamma-ray log is not a good indicator

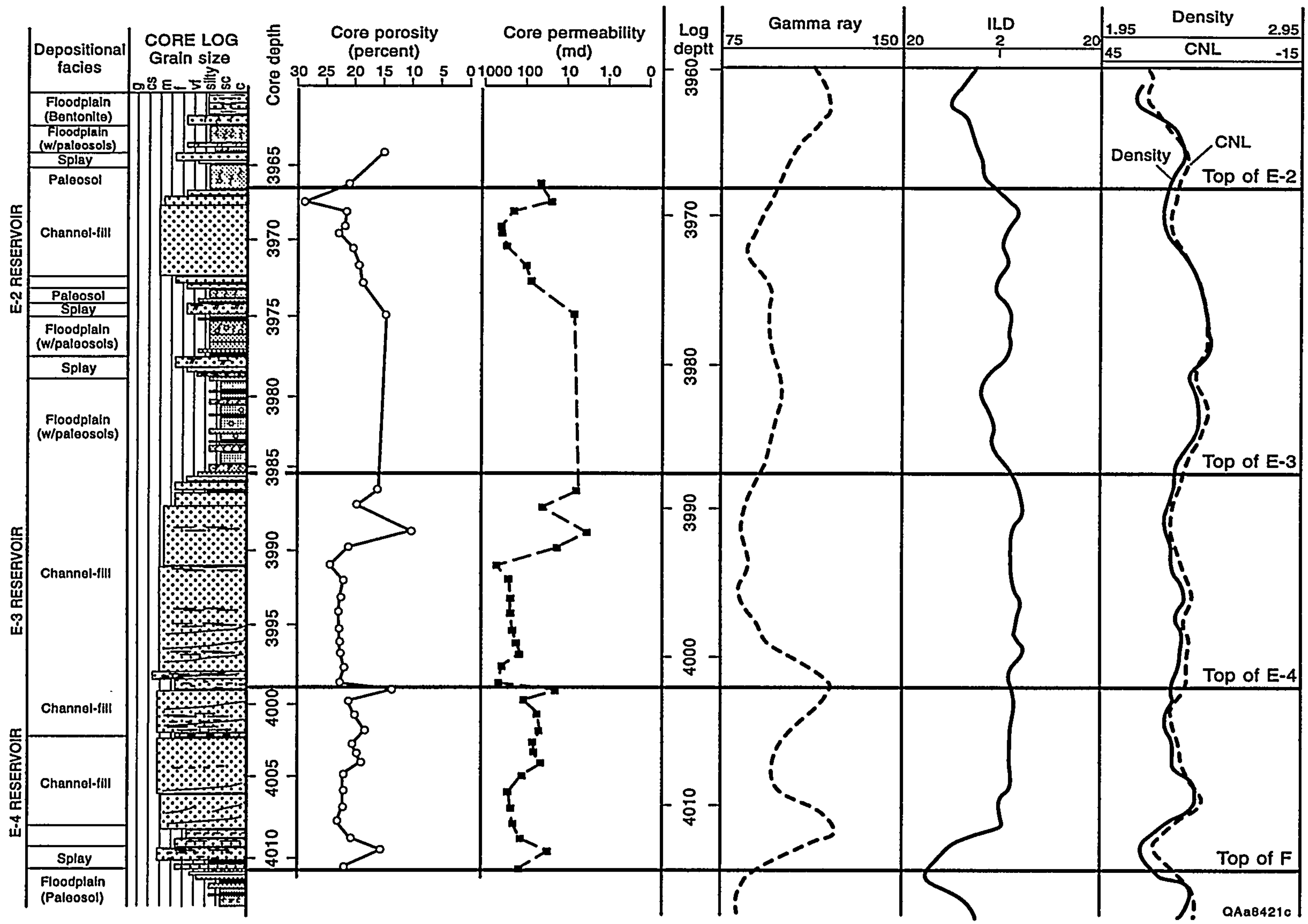


Figure 43. Core graphic log; porosity and permeability data; and gamma-ray, induction, and porosity logs, T. B. Slick 231:149 well. See Figure 25 for legend explanation.

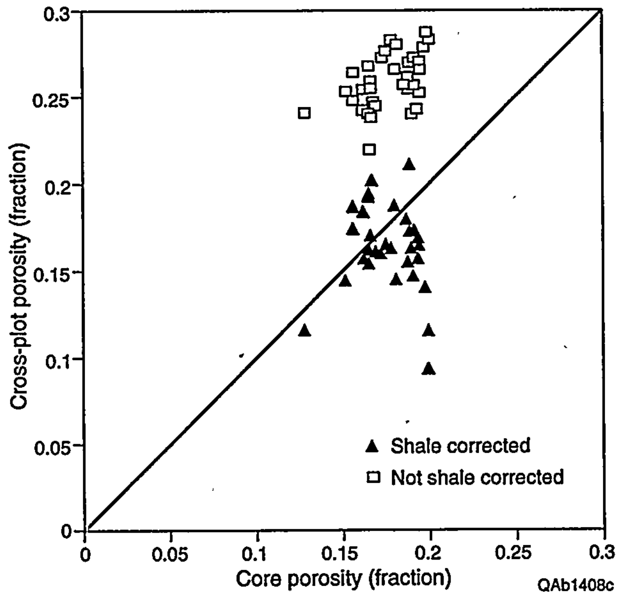


Figure 44. Comparison of shale-corrected and uncorrected cross-plot porosity versus core porosity.

of shale. Instead, the neutron log (CNL) is used as a shale indicator to calculate the shale fraction. The following equation is used to determine the shale volume:

Vsh =((CNL * (CNL - CNL sand)) / DI)** 0.5 (10)

where

DI = CNL shale * (CNL shale - CNL sand)

Vsh = bulk shale volume

CNL = CNL log value

CNL sand = the clean sand value read from the CNL log

CNL shale = the pure shale value read from the CNL log.

Shale determination is based on adjusting the CNL log reading between a pure sandstone and pure shale measurement. The clean sandstone and the pure shale values are respectively picked from local (Frio E reservoir) minimum and maximum values of the CNL log. For the Frio E interval the neutron clean sandstone value is 0.283 and the neutron shale value is 0.534, which were directly read from CNL log.

Porosity can be determined from the standard density-neutron cross plot applying a bulk volume shale correction. When calculating porosity a clay density of 2.124 g/cc and a neutron clay response of 0.534 were chosen. These values were determined from matching of density and neutron values at the depth where the pure shale volume (100% of shale) is present. It is noted that the value for the density of clay (2.124) corresponds to the published value of 2.120 for montmorillonite. The value for neutron clay (0.534) is not very much different from the published values of 0.6 for montmorillonite, and, this value is very close to the published value of between 0.519 and 0.500 for wet clay.

Correction for bulk volume shale is critical in determining correct porosity. The computed results for porosity without shale correction and shale corrected cross-plot porosity are compared with core porosity in Figure 44. Figure 44 clearly shows that shale corrected cross-plot porosity better represents core porosity than uncorrected cross-plot data, and the uncorrected data predicts overly optimistic porosity values.

Analysis of old logs

Resistivity measurements are used to obtain porosity from wireline logs where porosity logs are not available, for example, where wells predate the development of porosity logs. Several steps are needed to ascertain the resistivity derived porosity. These steps involve calculating Vcl in order to compensate for the conductivity of shale and then calculating a compensation for the effect of mud filtrate invasion.

Often with an old log suite, mud filtrate resistivity (Rmf) must be derived from mud resistivity (Rm). This conversion can be made by applying the equation below with C equal to 0.847, when mud weight is less than 10.8 pounds.

$$R_{mf} = C^*(Rm)^{1.07} \tag{11}$$

The first step in determining bulk volume shale is to calculate a clean sandstone SP response (SSP) for separate reservoirs. The need to derive a separate SSP for each reservoir occurs when they have different Rw values. The equation below is applied to determine SSP. When applying this equation Rw and Rmf must be at reservoir conditions and Tr must be reservoir temperature. Test the SSP value to make sure it does not exceed the minimum measured SP response. If this discrepancy occurs, the variables in the equation must be adjusted to make the minimum SP equal to the SSP.

Table 12. Representative saturation exponents from the Frio Fluvial-Deltaic Sandstone play.

Field	Cementation exponent	Saturation exponent
*Frio, South Texas	1.80	1.8
*Agua Dulce field	1.71	1.66
*Hollow Tree field	1.84	1.665
**Seeligson field	1.89	1.79
Average	**1.81**	**1.729**

SSP = ((0.133*Tr)+60)*log(Rw/Rmf) (12)

Having a reservoir specific SSP allows the determination of bulk volume shale (Vcl) from SP wireline curve. The calculation is made from the equation below.

Vcl = 1-(SP/SSP) (13)

Resistivity-derived porosity is now determined by calculating resistivity of near-borehole mixing zone resistivity (Rz) and applying the previously determined Vcl. The mixing zone resistivity is determined at formation temperature from formation water resistivity (Rw) and Rmf. For shallow invasion, Rz is calculated from the equation below.

Rz = 1/((o.1/Rw)+(.9/Rmf)) (14)

Resistivity porosity is then derived from the equation below.

fsn = $(a^*Rz/Rsn)^{1/m}$*(1-Vcl) (15)

Fluid Saturation Modeling

Formation resistivity factor

The saturation exponent applicable in Rincon field is taken as 1.7. Reported values range from 1.64 to 1.8 and average 1.7 (Table 12). This data source is limited, but values do not range significantly and the result of saturation calculation is not sensitive to saturation exponent in clean sandstone.

Formation resistivity measurements were conducted to define the cementation exponent *m*, which is used in the Archie equation to calculate formation water saturation. It has been documented in studies on the sensitivity of variables used in the Archie equation (Archie, 1942) that, unless reservoirs are characterized by low porosity (which these Frio reservoirs are not), variations in *m* will affect calculated water saturation values much more than values of *n*, the saturation exponent (Chen and Fang, 1986). Reported data on *m* values from the Frio in South Texas are very limited; at present we have found values ranging from 1.6 to 1.8 (Dewan, 1988). Reported Frio values are all less than the value 2.0, which is the standard default value generally used in the Archie equation for sandstones characterized by intergranular porosity. Higher values of *m* result in higher calculated water saturation values, which will in turn result in lower estimates for oil in place. Accurate estimates of water saturation are critical to delineating reasonable volumes of oil in place, and measurements of *m* on our own core samples will provide best possible estimates of values and variations in Sw in these Frio reservoir rock types.

Formation resistivity factor (FRF) was analyzed from laboratory measurements. A total of 14 measurements were obtained to determine the character of formation resistivity factor. The data are representative of the total range of pay as defined by porosity and permeability. Porosity ranges from 9 percent to 32 percent, and permeability ranges from 0.4 md to 747 md. Measured FRF values are also consistent with published data, ranging from 12.5 to 45.8. Converting FRF to cementation exponent values, assuming in the Archie equation a = 1, the values range from a minimum of 1.67 to a maximum is 2.4, and have a median of 1.81 (Table 13). This median is consistent with the average published cementation exponents in Table 13.

Modeling FRF for use in Archie equations was accomplished by assuming that porosity, permeability, and FRF are all interrelated. The tortuosity that the electrical path measures by FRF is a function of both porosity and permeability. Relatively high porosity but poor permeability could have a larger FRF value than a lower porosity with relatively higher permeability. Thus, modeling FRF by applying both porosity and permeability has the potential to determine more accurate values.

Table 13. Special core analysis and descriptive statistics for core samples in Rincon field.

Sample number	Depth (ft)	Porosity (%)	Permeability (md)	Formation resistivity factor	Cementation exponent (a=1)
1	3967.3	0.22	36.50	16.25	1.83
2	3974.6	0.16	7.20	25.20	1.74
3	3987	0.22	61.00	14.57	1.78
4	3988.7	0.11	3.30	44.58	1.73
5	3990.9	0.26	747.00	12.51	1.90
6	3999.6	0.23	98.00	16.82	1.90
7	4008.3	0.18	27.50	20.47	1.74
8	3872	0.30	172.00	13.85	2.18
9	3879	0.30	102.00	13.64	2.40
10	3891	0.32	320.00	15.52	2.40
11	3895	0.18	121.00	19.69	1.73
12	3950	0.22	130.00	14.78	1.80
13	3954	0.09	0.40	45.79	1.57
14	3959	0.20	370.00	14.15	1.82
Minimum		0.09	0.40	12.51	1.57
Maximum		0.32	747.00	45.79	2.40
Range		0.23	746.00	33.28	0.83
Average		0.21	156.85	20.56	1.89
Median		0.22	100.00	15.88	1.81
Skewness		–0.19	2.16	1.90	1.27

Both porosity and permeability display power relationships with FRF. Exponential, logarithmic, and power functions were all applied with porosity or permeability as the independent variable and FRF as the dependent variable. A porosity power function was determined to have a superior correlation coefficient (r square) of 0.86 and a permeability power function had a superior correlation coefficient of 0.82. Because both porosity and permeability strongly predict FRF, a multiple nonlinear regression is possible.

A robust multiple nonlinear regression model for the prediction of FRF was developed. The model in the equation below predicts FRF with porosity and permeability as input independent variables. The correlation is strong, displaying a multiple r of 0.95 and an F statistic of 53 compared to a significant F of 2.3 i 10^{-6}. The predictive capability is illustrated in Figure 45. Actual versus predicted values cluster closely around the 1-to-1 line with the exception of one

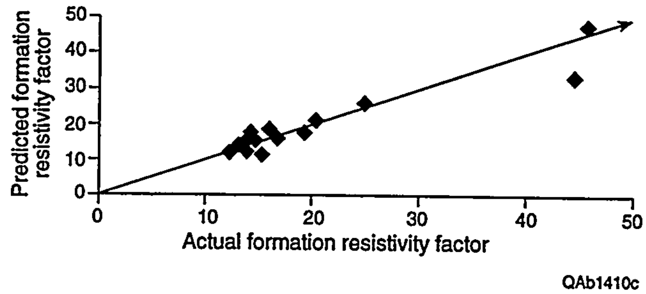


Figure 45. Results of the multiple nonlinear regression model for predicting FRF. The strong predictive capability is displayed by the clustering of the data around the 1-to-1 line.

data outlier. This outlier is a data point that displays a higher FRF for the measured porosity and permeability.

$$FRF = 10^{(1.029-.58*\log(porosity)-0.095*\log(permeability))} \tag{16}$$

where porosity is a fraction and permeability is in millidarcys.

Capillary pressure modeling

The primary objective of the mercury-injection capillary pressure measurements was to determine the distribution of pore throat sizes present in each sample, and to ascertain any differences in pore types among the various rock types identified from core description and evaluation of conventional core analysis data. Thin sections were prepared for each sample selected for capillary pressure studies to provide visual description of pore geometries and estimates of pore sizes. The mercury-injection technique is the most commonly used and fastest method of capillary pressure measurement, and it yields the maximum number of data values. Pore geometry identified from these measurements will provide insight into heterogeneity present within individual samples. Pore throat size derived from capillary pressure tests will form the basis for estimates of irreducible water saturation. These estimates of Swirr will in turn be used in subsequent resource calculations. Capillary pressure results may also be used to estimate reservoir efficiency.

Initial connate water saturation was modeled from capillary pressure data as a function of porosity, permeability, and height above free water. From exploratory statistical data analysis it was found that both porosity and permeability, as well as height above free water, controlled

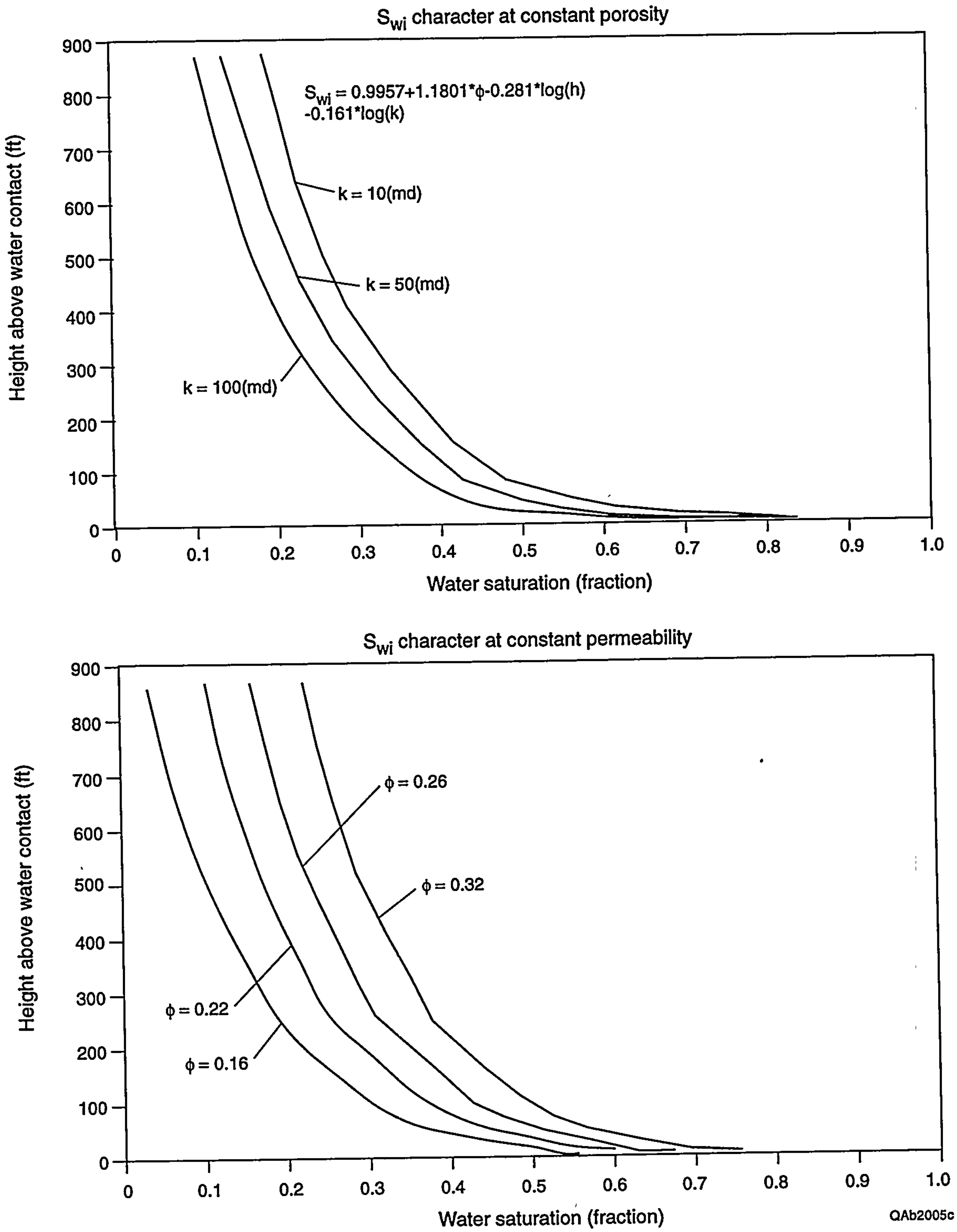


Figure 46. Initial water saturation is modeled from a multi-nonlinear regression equation with porosity, permeability, and height above free-water as the independent variables.

initial water saturation. The relationship between initial water saturation and permeability and height above free water is nonlinear, whereas the relationship between initial water saturation and porosity is linear. Multi-nonlinear regression was applied to develop an initial water saturation function. The character of this function is illustrated in Figure 46. The multi-nonlinear equation is statistically robust, having a correlation coefficient (r) of 0.88. The utility of this equation is that it can be applied when, because of lack of data, the Archie equation cannot be applied.

Residual oil saturation

Core flood tests were conducted on 15 core plugs to acquire data on residual oil saturation (S_{or}) and end point relative permeability. There are no good available residual oil saturation data for these reservoirs, and values for S_{or} reported for reservoirs throughout the Frio play range widely from 10 to 38 percent (Holtz and McRae, 1995). S_{or} data are obviously critical to obtaining reasonable estimates of remaining mobile oil.

Residual oil saturation can be characterized as low, with a long tail on the high side. The mean and median are nearly identical at 28.8 percent, indicating a strong central tendency. The standard deviation is a low 9 percent, although the range is large (48 percent). The large range is due to a single high outlier value of 62.5 percent. Because the data sample is small, it cannot be determined if this high data point is valid. The long tail is evident in the high skewness value of 1.74 and on the histogram shown in Figure 47.

Reserve Growth Potential

The potential for infield resource additions is a function of the original oil volume in place, the present level of development, and the degree of internal geologic complexity of the reservoir being produced. Studies of the Frio D and E reservoirs in Rincon field have identified the current level of development in individual reservoir units and documented that reservoir geometry within each stratigraphic reservoir interval is variable and provides important controls on the level of flow communication within a single reservoir unit. Stratigraphic heterogeneity and

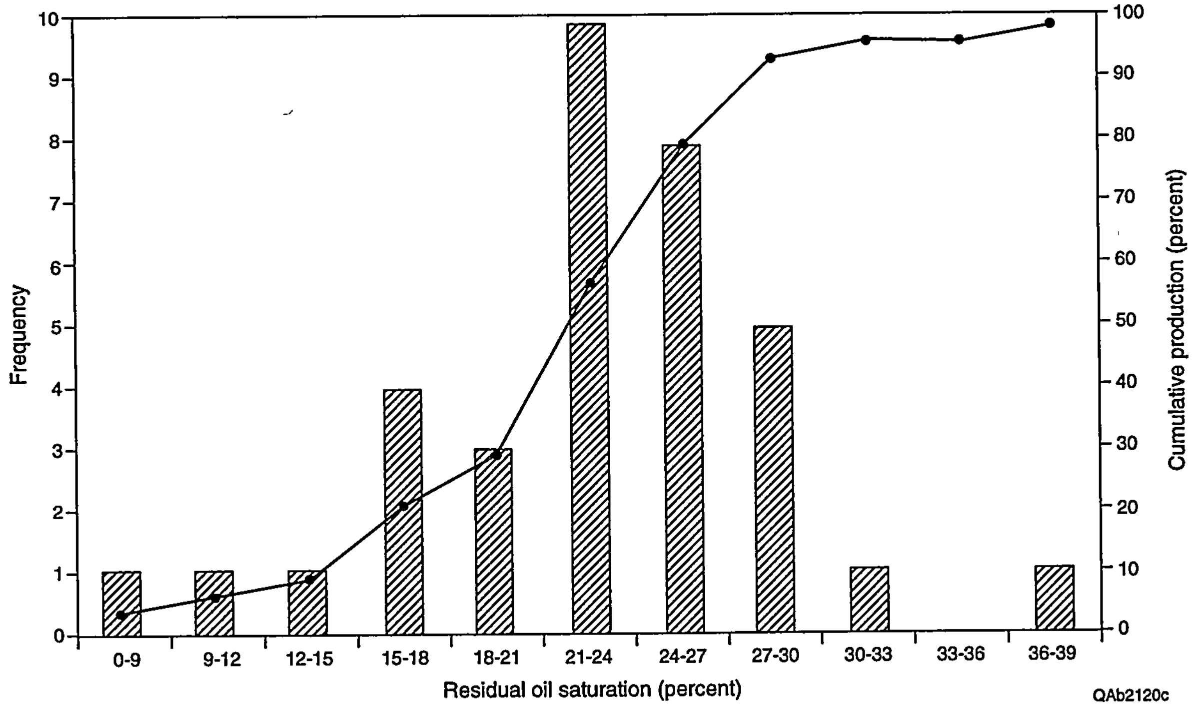


Figure 47. Residual oil saturation measured from core flood tests indicates a wide range of possibilities due to high and low tails on the distribution.

variability in reservoir quality exhibited within these reservoirs are directly responsible for the distribution of original oil in place and have also been a primary control on present recovery efficiencies. The wide range of oil volumes produced from wells completed in the same reservoir is an additional indication of the presence of interwell-scale heterogeneity.

Frio D reservoir sandstones have more complex facies patterns and a greater degree of stratigraphic variability, and, as a result, the composite reservoir zone has a significantly lower recovery efficiency than do E series reservoirs. The relatively poor recovery efficiency of the Frio D reservoir zone is caused by the fact that current well spacing is greater than the size of reservoir compartments that collectively make up the total storage space of the mobile oil resource in the Frio D reservoir zone. As a consequence, reservoirs of the Frio D zone represent a greater opportunity for future reserve growth than those of the Frio E zone.

Conclusions

Assessing the potential for incremental reserve growth in mature fields, such as those producing from Frio reservoirs in South Texas, requires identifying the location and volume of the remaining resource in the reservoir (Tyler and Finley, 1991). Detailed interwell-scale studies of selected reservoirs serve to characterize reservoir flow-unit architecture and determine the controls reservoir characteristics exert on the distribution of original oil volumes, present production trends, and locations and volumes of unrecovered mobile oil in untapped and incompletely drained zones. With an estimated 1.6 Bbbl of remaining recoverable oil, Frio reservoirs in South Texas represent a significant resource worthy of these efforts.

Different Frio reservoir architectural styles possess characteristic geometries and permeability distributions that directly impact their ability to produce hydrocarbons. Studies of the Frio D and E reservoir zones in Rincon field demonstrate that sandstone architecture is a primary control on recovery efficiency. The architectural styles exhibited by the D and E reservoirs in Rincon field include aggradational, retrogradational, and progradational stacking patterns. The D/E reservoir sequence records an evolution from aggradational, vertically stacked and more laterally isolated units in the lower E zones to retrogradational, landward-stepping units in the upper E reservoir that are also vertically stacked but have increased lateral communication that is probably responsible for higher recovery efficiencies. Frio D reservoir sandstones have more complex facies patterns and a greater degree of stratigraphic variability, and, as a result, the composite reservoir zone has a significantly lower recovery efficiency than do E series reservoirs. The relatively poor recovery efficiency of the Frio D reservoir zone is caused by the fact that current well spacing is greater than the size of reservoir compartments that collectively make up the total storage space of the mobile oil resource in the Frio D reservoir zone.

The techniques of multidisciplinary advanced reservoirs characterization that have been used in Rincon field serve as a useful template for additional recovery efforts in other mature fluvial-deltaic reservoirs throughout the Frio Fluvial-Deltaic (Vicksburg Fault Zone) Play. The specific methodologies can also be applied to other mature fluvial-deltaic reservoirs throughout the United States because similar facies in those reservoirs will result in similar architectures. Furthermore, the basic tenets of multidisciplinary advanced reservoir characterization, including geological and engineering interpretations enhanced by high-frequency stratigraphic studies and facies-based petrophysical analysis, will enhance the understanding of any mature reservoir, regardless of its depositional setting.

T-C-B FIELD RESERVOIR STUDIES

P. R. Knox and J. G. Paine

Introduction

Objectives for the study of Tijerina-Canales-Blucher (T-C-B) field included the delineation of untapped/incompletely drained compartments and the evaluation of potential for new pools within selected reservoir intervals, as well as documentation of these features for purposes of technology transfer. The reservoir intervals studied in detail were selected on the basis of certain criteria (McRae and others, 1995) following a review of all reservoir intervals within T-C-B field. Two reservoir intervals in the Middle Frio Formation, the Scott and Whitehill, comprising a fourth-order genetic unit, were selected for detailed study because they represent significant past production, are unfaulted, and show a spectrum of fluvial upper delta plain architectures.

Advanced characterization of the Scott and Whitehill zones has been completed and specific reserve-growth opportunities have been delineated. Following subregional study to identify the bounding surfaces correlative to fourth-order marine flooding surfaces, detailed well log interpretation allowed further subdivision of the Scott/Whitehill interval into fifth-order genetic units within the T-C-B area. Facies, net sandstone, and compartment production maps were then prepared to document general compartment boundaries and past production history for each fifth-order interval. Volumetric analysis was combined with other reservoir history data to identify approximate compartment areas drained. The distribution of undrained areas was then compared with the location of open well bores to plan infill and recompletion opportunities. Results of the Scott/Whitehill study indicate that sandstones within a fourth-order genetic unit show a systematic and predictable change in architecture and internal heterogeneity from base to top, and that these relationships can be used to predict reserve-growth potential in other reservoirs on a quick-look basis.

Interpretation of reservoir compartmentalization has been presented to the field operator, along with specific recommendations for recompletion and infill drilling opportunities. Because of various economic and operational considerations, only one recompletion has been done. This opportunity, evaluated as having moderate risk, is currently producing at economic rates.

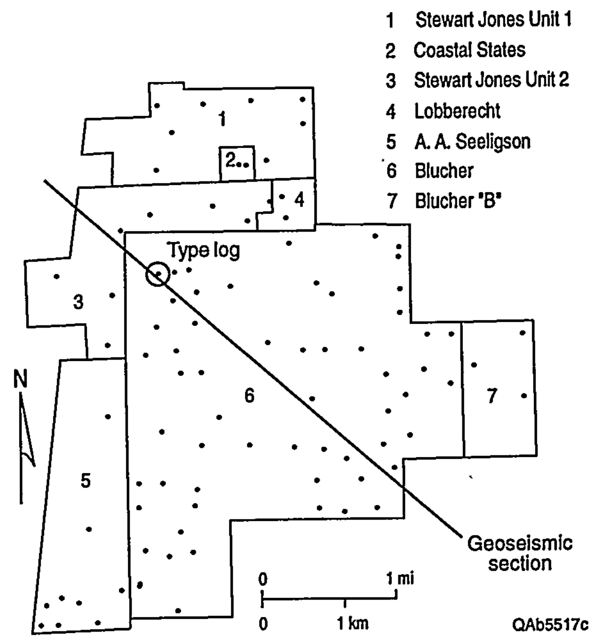


Figure 48. Map of study area in T-C-B field showing lease boundaries and approximate location of geoseismic section (Fig. 51).

Location, History, and Geologic Setting of T-C-B Field

Location

Tijerina-Canales-Blucher field is located in the northern half of the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) oil play, about 55 mi southwest of Corpus Christi, and it straddles the border between Kleberg and southern Jim Wells Counties (Fig. 17). The field lies in a structural low between large rollover anticlines in the Seeligson and La Gloria fields to the northeast and southwest, respectively. Movement on the Sam Fordyce Fault, a part of the regional Vicksburg Fault Zone, and subsidiary synthetic and antithetic faults, has generated a fault-segmented rollover structure in the lower Frio reservoir section. Accumulation of most of the sediment within the middle Frio postdates most of the fault movement, creating a low-relief unfaulted (to subtly faulted) anticline slightly offset from the crest of the underlying rollover structure.

The area selected for study is a contiguous 4,800-acre block, located at the southwest edge of the field and operated by Mobil Exploration and Producing U.S., Inc. The block is primarily composed of the 3,500-acre Blucher lease, which is adjoined by the smaller Blucher B, A. A. Seeligson, Lobberecht, and Stewart & Jones I and II leases (Fig. 48). Mobil has supplied well log, core, and production data for more than 80 wells on this lease block.

Development History

The many stacked reservoirs in the various areas of T-C-B field have been discovered and produced by several operators over the years, beginning in the late 1930's. Original operators include Sun (now Oryx), Humble (now Exxon), Texaco, and Mobil. Cumulative oil production from Frio reservoirs in the T-C-B field is reported at more than 50 MMSTB. T-C-B is in a mature stage of development, and production has declined drastically since the 1970's due, in part, to the abandonment of a large number of wells. Recent operator focus has turned to the deeper, more complexly faulted reservoirs of the Vicksburg Formation as a result of improvements in seismic technology. Consequently, the mature Frio reservoirs are suffering from a lack of investigation and are in danger of premature abandonment.

The area of T-C-B field selected for detailed study, the western Blucher portion, was discovered by Shell in 1939 and subsequently sold to La Gloria Corporation in 1942. La Gloria operated the field until Mobil purchased the leases in 1967. Recent deeper drilling by Mobil in the late 1980's targeted complex fault blocks interpreted from 2-D seismic data. During 1994, 3-D seismic data were gathered over the Mobil leases, and processing was completed in early 1995. As of 1992, there were 24 active wells, 12 idle wells, and 28 abandoned wells on the Blucher lease. Production has come from more than 40 separate reservoirs in the Vicksburg, lower Frio, and middle Frio Formations. Data from the Railroad Commission of Texas indicate that no Frio reservoir has been drilled at closer than a 40-acre spacing, an indication of substantial potential for infill drilling opportunities.

Stratigraphic Framework

A detailed discussion of the stratigraphic framework for T-C-B reservoirs can be found in McRae and others (1994). The following is a summary of the general setting of Frio reservoirs within the T-C-B area.

Frio sediments in the vicinity of T-C-B field were deposited by the Norias deltaic and Gueydan fluvial depositional systems that filled the axis of the Rio Grande structural embayment (Fig. 49).

The location of T-C-B field lies near the boundary of these two depositional systems. During early Frio times, the Norias delta occupied the T-C-B area. Because of continuous progradation, the Gueydan Fluvial system (equivalent to the upper delta plain of the Norias system) eventually encroached on the T-C-B area from the northwest, occupying the area throughout the middle Frio time.

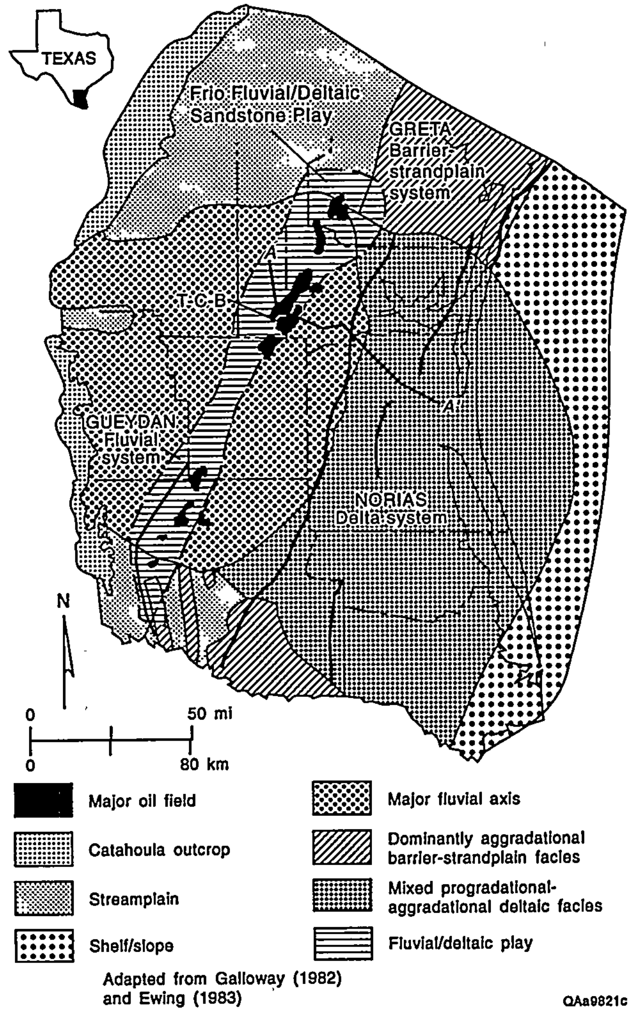


Figure 49. Location of Tijerina-Canales-Blucher (T-C-B) field within the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) Play in South Texas. Also shown is the position of T-C-B field with respect to the Norias delta and Gueydan fluvial depositional systems of Galloway (1982). Cross section A–A′ is shown in Figure 61.

Productive reservoir sandstones in T-C-B field range in depth from 5,500 to 8,000 ft and lie within the middle and lower members of the upper Oligocene Frio Formation and the upper part of the lower Oligocene Vicksburg Formation, as shown in the field type log (Fig. 50). The thick massive progradational deltaic to shallow-water marine sandstones of the upper portion of the Vicksburg (Taylor and Al-Shaieb, 1986) are extensively faulted and produce mostly gas. The lower Frio Formation in T-C-B field ranges in depth from 6,600 to 7,600 ft and contains many 10- to 30-ft-thick deltaic reservoir sandstones in a dominantly shaly interval. This section is moderately faulted and produces both oil and gas, with gas predominating. The mostly oil-productive reservoirs of the middle Frio Formation range in depth from 5,500 to 6,600 ft and occur within an interval of thick and abundant fluvial sandstones interbedded with floodplain mudstones.

In Seeligson field, directly northwest of T-C-B field, the contact between the Vicksburg Formation and lower Frio unit is reportedly unconformable (Ambrose and others, 1992). Because

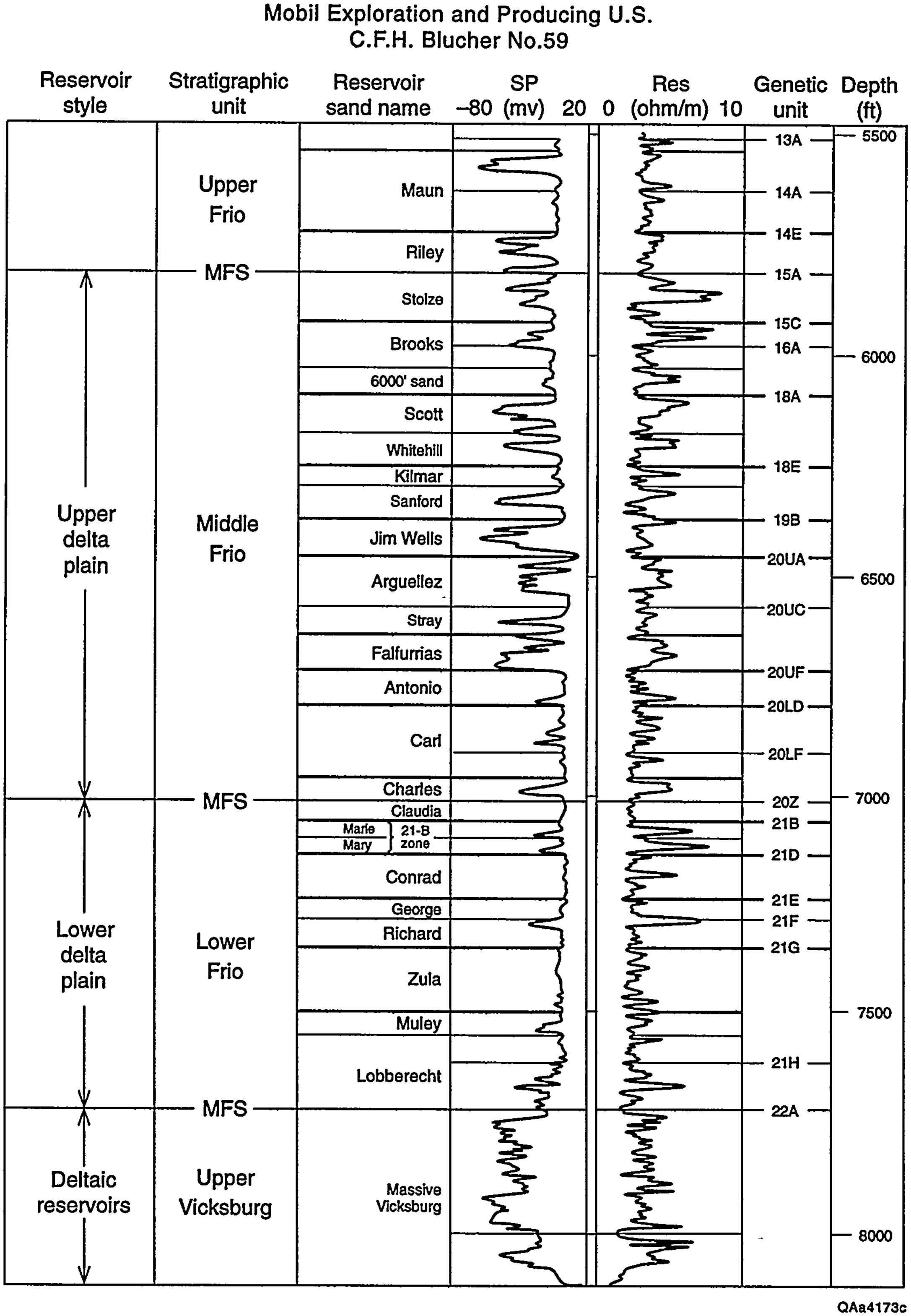


Figure 50. Representative log from T-C-B field illustrating generalized stratigraphy and nomenclature of productive reservoir sandstones.

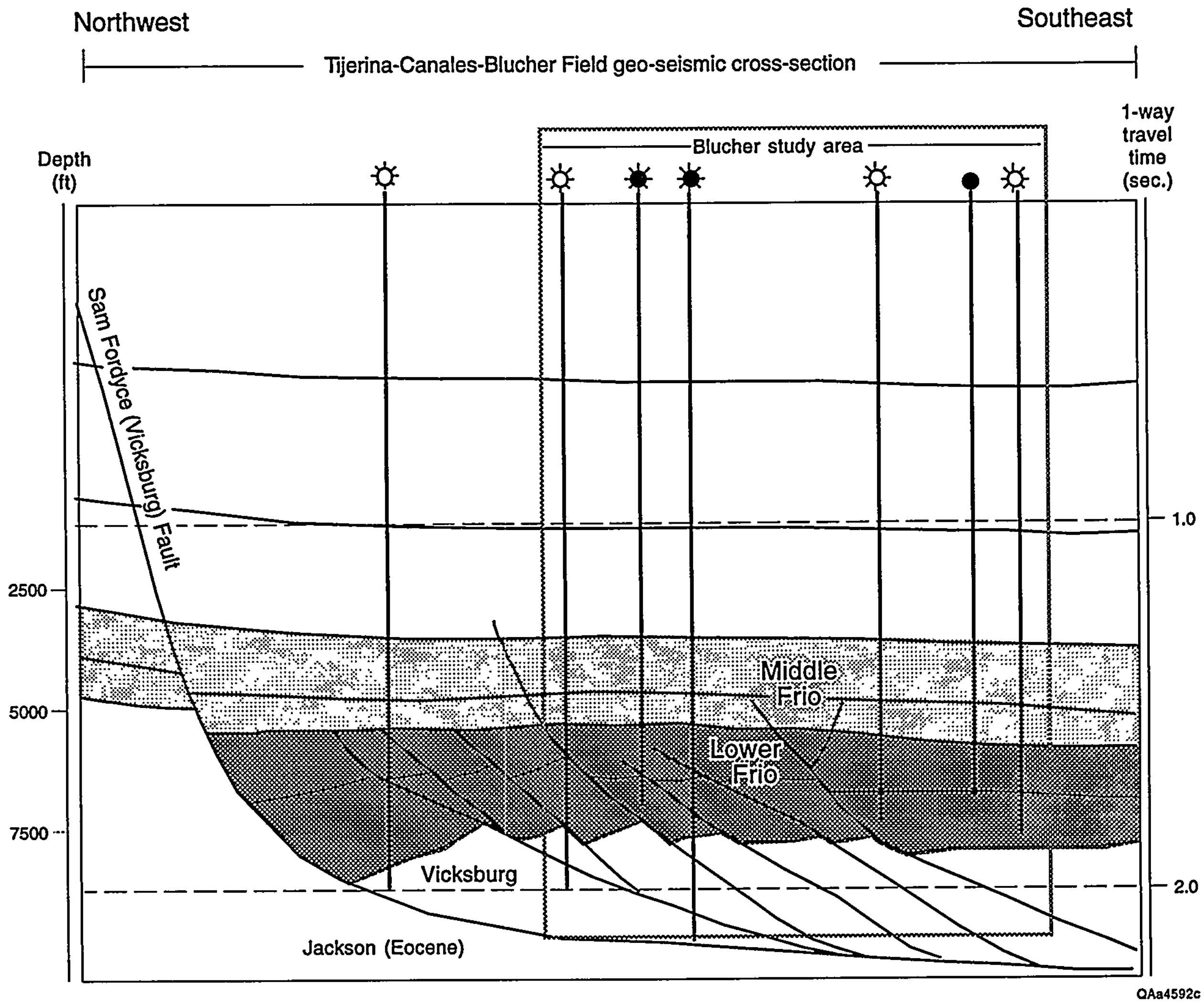


Figure 51. Northwest-to-southeast geoseismic dip section across T-C-B field illustrating the general structural setting of Frio and Vicksburg reservoir sections. The base of the middle Frio is a significant unconformity separating structurally complicated reservoirs below from less faulted reservoirs above. Seismic interpretation provided by Mobil Exploration and Producing, U.S. See Figure 48 for approximate location of section.

the Vicksburg is not a focus of this study, insufficient work has been done to confirm an unconformable relationship between the two units in T-C-B field. The contact between the lower and middle Frio is a subtle but moderately profound unconformity. Well log correlation within T-C-B field has identified mild truncation in the underlying lower Frio sediments and demonstrates the abrupt change from a sandstone-poor to a sandstone-dominated interval across the contact. However, a two-dimensional seismic line (Fig. 51) illustrates that the significance of the surface exceeds that of minor erosion. The lower Frio is moderately growth faulted, with significant expansion of section at the updip edge of the field adjacent to the Sam Fordyce Fault, whereas the middle Frio is, at best, mildly faulted with no expansion of section. This difference in style exaggerates the appearance of truncation at the unconformable boundary.

The transition from the middle Frio to the overlying upper Frio is subtle in the T-C-B area and has not been investigated in detail. On the basis of subregional correlation, there is a significant change at the 15A marker (Figure 50) from dominantly aggradational to dominantly retrogradational architecture that may correspond to the transition from middle to upper Frio as identified by Galloway and others (1982).

Methodology

The primary objective in T-C-B field, that of identifying specific reserve-growth opportunities in selected reservoirs, required advanced technology reservoir characterization that integrated geological, geophysical, and engineering methods (the methodology is documented in Holtz and others, 1996). An important technical goal was to apply observations from a previous outcrop study of Cretaceous fluvial-deltaic sandstones of the Ferron Formation of central Utah. This study, funded by the Gas Research Institute and various industrial associates, concluded that reservoir architecture and heterogeneity varies systematically within a fourth-order genetic unit (Barton, 1994), possibly as a consequence of systematic changes in accommodation rate. The following two sections briefly review both the observations from the Ferron outcrop study and the general reservoir characterization methods used to investigate the Scott/Whitehill reservoir interval of T-C-B field.

Outcrop-Based Models for Predicting Reservoir Architecture

The Upper Cretaceous (Turonian) Ferron Sandstone of central Utah was deposited in a fluvial-deltaic depositional system that existed on the west margin of the Cretaceous Interior Seaway (Barton, 1994) and carried sediments from the rising thrust belt in the west to the rapidly subsiding foreland basin to the east. Total accommodation rates for the Ferron are similar to those for the Frio Formation in the Texas Gulf Coast: the Ferron spans 1.6 m.y. and is 800 ft thick, whereas the Frio ranges from 800 to 4,000+ ft and accumulated in a similar time span. Gardner (1991) divided the Ferron into seven fourth-order genetic sequences, GS 1 through GS 7 (Fig. 52a), each bounded by a marine flooding surface and being equivalent to a parasequence, as defined by Van Wagoner and others (1988). These genetic sequences vary from strongly progradational or seaward stepping in the lower portion (GS 1 and 2), to aggradational or vertically stacked in the middle (GS 3 and 4), to retrogradational or landward-stepping at the top of the depositional cycle (GS 5, 6, and 7).

Barton (1994) examined, in detail, outcrops of distributary-channel deposits of two genetic sequences, GS 2 and 5, and identified two styles of deposits exhibiting distinctly different external architecture and internal heterogeneity. He determined that variable internal heterogeneity is a function of the preservation potential of different lithofacies and differences in the content of channel lag deposits.

Distributary-channel-belt deposits that formed during the strongly seaward-stepping portion of a depositional cycle (GS 2), at which time the rate of sediment influx was greater than the rate of generation of accommodation space, are typically narrow and few in number, and consequently cover little area in map view (Fig. 52b). Internally, these channel belts consist of sandy, vertically amalgamated channel deposits dominated by trough-fill cross-stratified lithofacies of basal channel deposits. The base of individual channel deposits commonly contains a lag of dispersed and rounded mudstone and sandstone clasts, creating a layer of slightly reduced permeability at the contact between vertically adjacent channels. Low-permeability lithofacies from the upper portions of individual channel deposits, such as finer grained ripple strata and siltstones, are uncommon, having been removed by erosion during the incision and filling of subsequent channels. Barton (1994) ascribed the dominance of erosion over deposition in these channels, and thus their relative internal homogeneity, to the low accommodation rates under which they were deposited. The straight, narrow configuration of these channel belts is also a

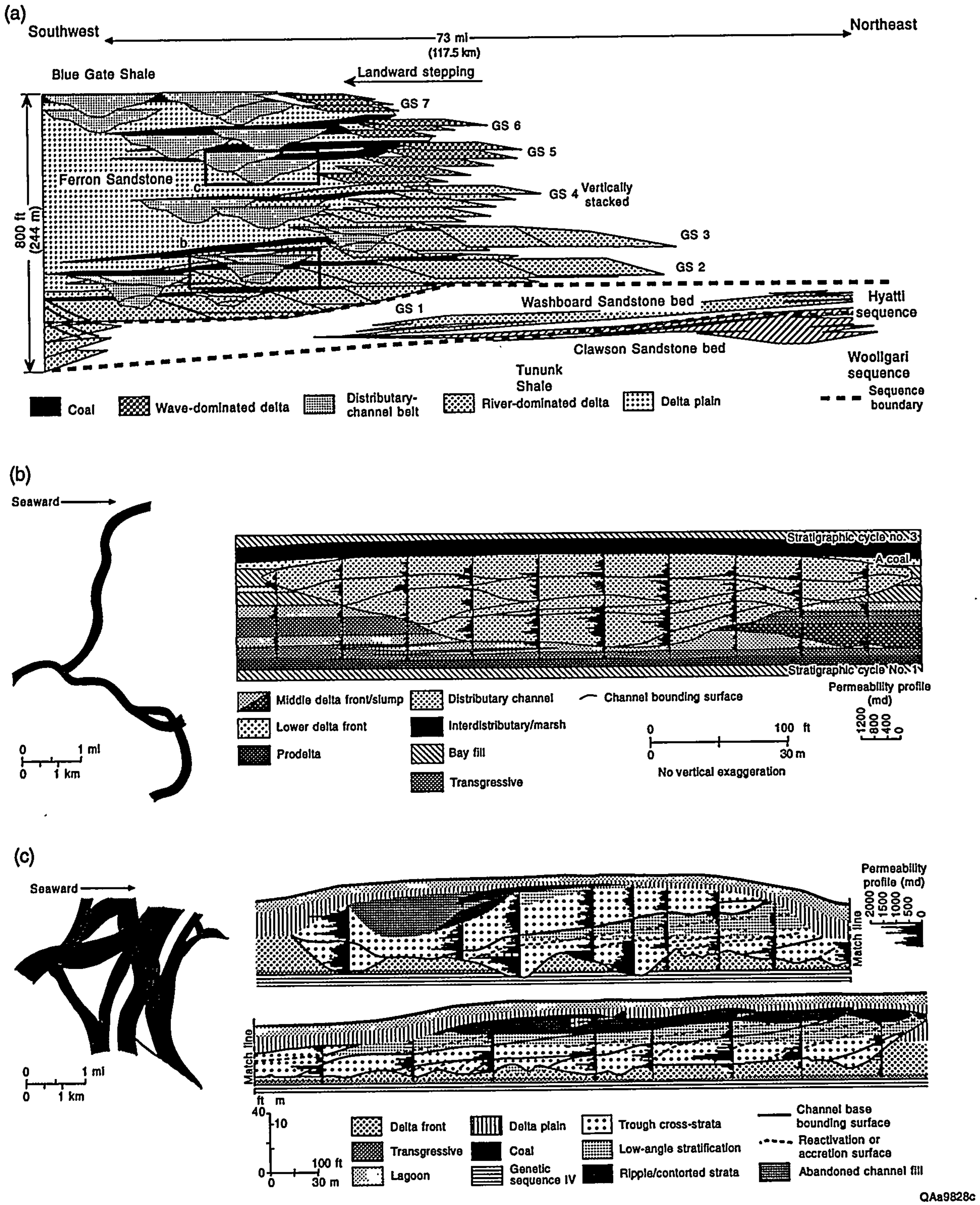


Figure 52. Genetic stacking pattern and architecture of the Cretaceous (Turonian) Ferron Sandstone of central Utah. (a) Stacking pattern for the Ferron 3rd-order depositional unit, composed of a depositional cycle of 4th-order units. Note locations of distributary channel fills detailed in (b) and (c). (b) Map view architecture and internal lithofacies of distributary channel fills in the low-accommodation seaward-stepping GS 2 4th-order unit. (c) Map view architecture and internal lithofacies of distributary channel fills in the high-accommodation landward-stepping GS 5. From Barton (1994).

consequence of low accommodation in that the channel system, previously meandering in part, must stretch to cover the increasing distance to the seaward-stepping distributary mouth, eliminating the tendency toward lateral migration and meandering. Distributaries are few because there is no opportunity for the channel to avulse, having never built substantially higher than the surrounding delta plain.

In contrast, distributary-channel-belt deposits formed during the landward-stepping portion of the Ferron depositional cycle, in which the rate of accommodation exceeded the rate of sediment influx, are broader and more numerous, covering a greater percentage of area in map view than those of the seaward-stepping unit. Internally, channel belts are more lithologically heterogeneous, containing nearly complete vertical channel deposit successions including trough cross-stratification, low-angle inclined stratification, rippled beds, and abandoned channel-fill mudstones (Fig. 52c). Channel bases are commonly draped by a lag deposit containing abundant deformed mudstone clasts that form a very low permeability layer between channel deposits that are in sandstone-on-sandstone contact. This depositional style indicates laterally migrating channels constrained within topographically high levee systems and flanked by large areas of low-lying floodplain, leading to frequent channel avulsion. This is consistent with the anticipated morphodynamic response of a distributary to rising base level, in which a channel of fixed length must increase its sinuosity as the distributary mouth steps landward. More complete preservation of individual, internally heterolithic channel deposits is a consequence of higher accommodation rates, in which subsequent channels do not cut as deeply into previous channel deposits because of a larger rise in base level (relative sea level) in the intervening period.

The two end-member distributary channel styles identified by Barton (1994) would have very different characteristics if they were subsurface oil and gas reservoirs. The narrow seaward-stepping distributary channel belts would not be effectively contacted by pattern-style drilling, but individual completions would drain considerable reservoir volumes because of the internal homogeneity of the channel belts. Conversely, the broader, more numerous distributary channel belts of the landward-stepping units would be more commonly contacted by pattern drilling, but completions would drain smaller areas because of the internal heterogeneity resulting from more abundant low-permeability lithologies and mudclast conglomerate layers at channel boundaries.

Geological Reservoir Characterization Methods

As can be seen from the above discussion, the identification of third- and fourth-order marine flooding surfaces can provide a powerful framework in which to interpret reservoir architecture from limited well log data. Consequently, one of the first and most important steps in the reservoir characterization process is subregional correlation of the stratigraphic interval of interest far enough downdip to clearly locate fourth-order marine flooding surfaces. Once these have been defined, the more subtle fifth-order surfaces that subdivide the fourth-order unit can be identified within the field area. The fifth-order units frequently correspond to what operators identify as individual reservoir subzones.

Facies and net sandstone maps are then made for each fifth-order unit to define general reservoir architecture. Individual reservoir compartments can commonly be interpreted from these maps. Stratigraphic analysis of 3-D seismic data may help to interpret compartment boundaries at the between-well scale. Structure maps are then created for each compartment and fluid contacts are determined and annotated on the maps. Net pay maps are created for each compartment and production records are consulted to allow annotation of past drainage from the compartment. Petrophysical parameters such as porosity and water saturation are determined in order to calculate original hydrocarbons in place and area drained by each completion. A compartment status map is then created that incorporates original net pay and drainage from past production. Typical drainage radii of past completions are then compared with areas of undrained reservoir to evaluate the potential for recompletions in existing wells and the need for geologically targeted infill drilling. Expected production from economically viable recompletions and infill wells is then summed and represents reserve-growth potential.

Geophysical Reservoir Characterization Methods

Acquisition, processing, and analysis

A three-dimensional seismic data set used to analyze subtle stratigraphic features in the T-C-B field was provided to the project by Mobil. The data set, which covers 14 mi^2 in Kleberg and Jim Wells counties, consists of 347 east-west inlines and 280 north-south crosslines (fig. 53). The data were acquired in 1994 by Grant Geophysical using four vibrators, 10 Hz geophones, and a 2 ms sample interval (CGG, 1995). Stacking fold was between 22 and 24; bin size was 82 ft.

Original processing was by CGG. Problems with acquisition geometry, consistent well ties, and excessive air blast led Mobil to have EnTec Energy Consultants, Ltd. (EnTec) reprocess the data. EnTec also had problems with consistent well ties and ultimately recommended that Mobil acquire a vertical seismic profile (VSP) in the Blucher B-3 well. The VSP allowed EnTec to establish reliable time-to-depth ties and to produce time-converted log suites for four of the wells in the field. These wells were used as the control wells for our seismic horizon mapping.

The reprocessed three-dimensional seismic data volume was received in January 1996. Structural and stratigraphic analysis of the data was accomplished using the software Photon SeisX operating on Sun workstations at the Bureau of Economic Geology. Data analysis included (a) establishing time-to-depth ties between digitized log suites and the seismic data using checkshot surveys, synthetic seismograms, and the vertical seismic profile, (b) identifying key mappable seismic horizons within the stratigraphic zone of interest, (c) picking peaks, troughs, or zero crossings for the seismic horizons of interest and extending those picks across the data volume, (d) mapping faults within the heavily growth-faulted Vicksburg zone and the subtly faulted Frio section, (e) constructing structure maps (in time) for key seismic horizons, (f) creating time slices above and below key flattened horizons to show subtle stratigraphic features, and (g) creating seismic amplitude maps on various time slices and seismic horizons for comparison with net sandstone and facies maps created using well logs alone.

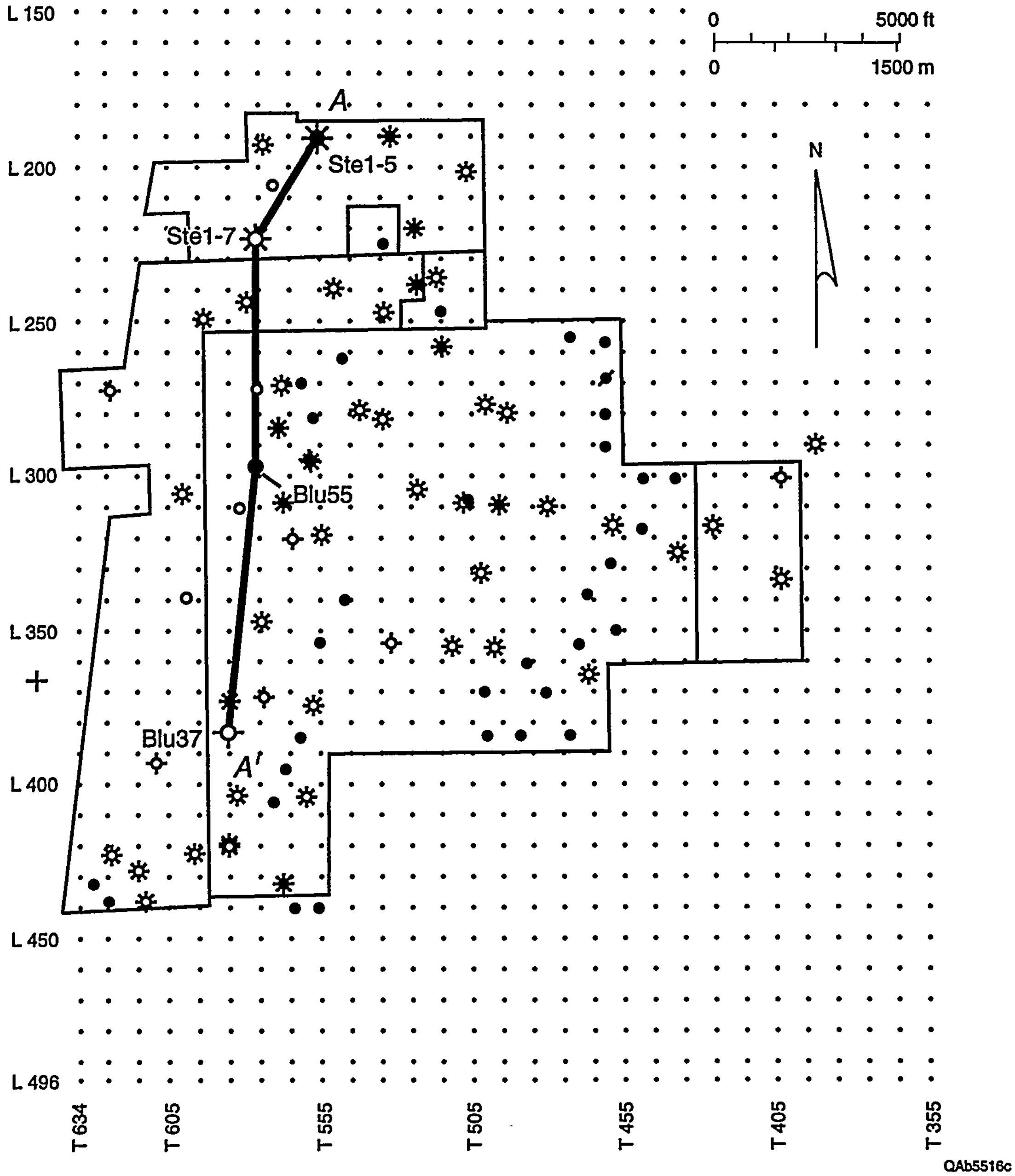


Figure 53. Major inlines (east-west), crosslines (north-south), well locations, and lease block boundaries within the T-C-B three-dimensional seismic data set provided by Mobil. Also shown are the locations of arbitrary seismic strike section A–A′ and dip section B–B′.

Limits of horizontal and vertical resolution

Analysis of acquisition geometry and seismic data characteristics allows us to establish theoretical limits for both the horizontal and vertical resolution of the T-C-B seismic data set. Aside from frequency content and rock property considerations, the practical limit of lateral

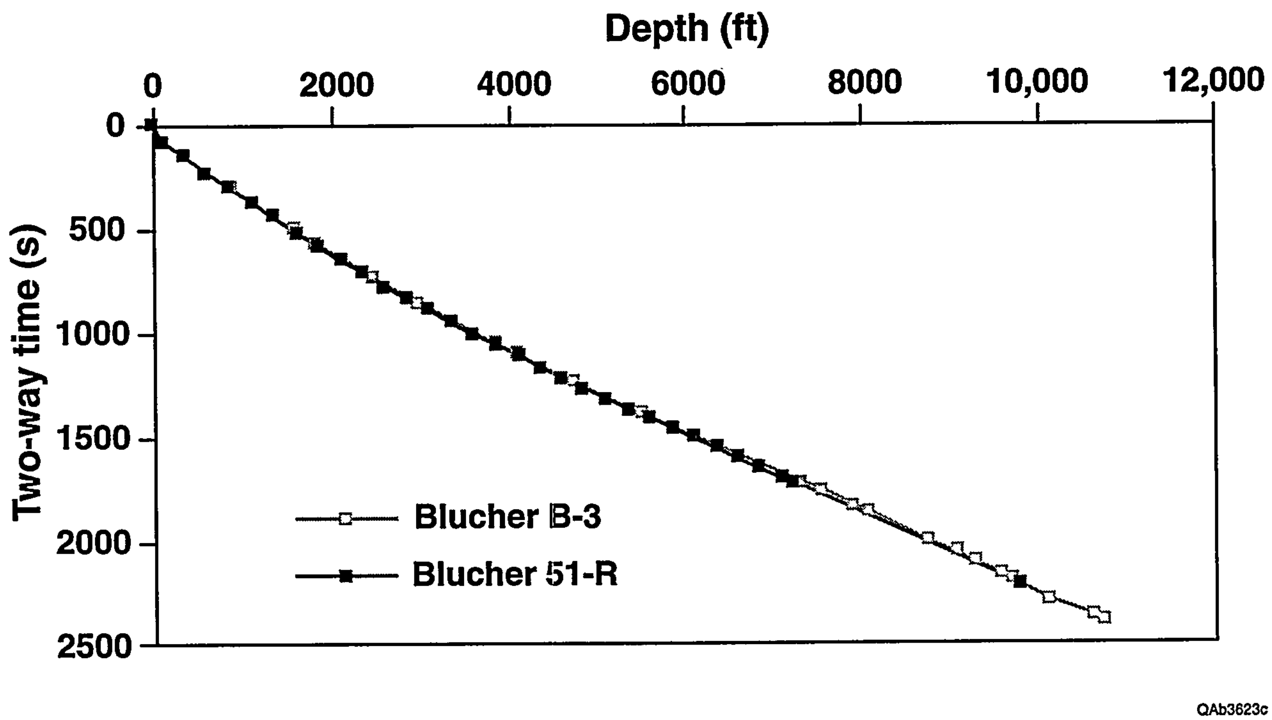


Figure 54. Two-way time versus depth established from checkshot surveys in the Blucher B-3 well in the eastern part of the data volume and the Blucher 51-R well in the western part of the data volume.

resolution is established by the fact that features smaller than three or four bins across cannot be distinguished. Bin size for the T-C-B data set is 82 ft; the smallest identifiable feature is thus 250 to 300 ft across.

Vertical resolution depends upon compressional wave velocity of the material and frequency content of the seismic signal. For the depth range of interest in the T-C-B field, which extends from the lower Frio 21B horizon at about 7,000 ft to the upper Frio 13A horizon at about 5,500 ft, seismic velocities are in the 10,000 ft/sec range (fig. 54). Frequency content of the T-C-B data is limited (fig. 55), perhaps because of acquisition geometry problems. Seismic signal is above background noise between about 10 and 50 Hz. When combined with typical seismic velocities of 10,000 ft/sec, modeling calculations illustrate that two adjacent reflectors do not begin to be resolved until their separation is about 125 ft (fig. 56). In other words, two stratigraphic horizons separated by less than this distance cannot be resolved into separate reflectors.

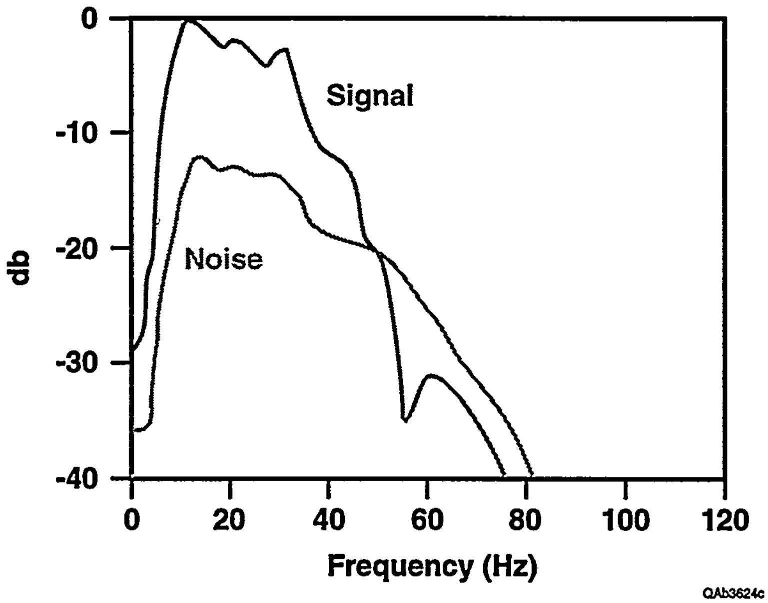


Figure 55. Frequency content for stacked data from inline 315. Adapted from EnTec (1995).

Tying seismic data to stratigraphic markers

Because this study is principally one of subtle stratigraphic traps, the depth range of interest is above the faulted Vicksburg section. Most of the seismic analysis was confined to the dominantly upper delta plain deposits of the middle Frio, although units as high as the upper Frio 13A and as deep as the lower Frio 21-B were examined (fig. 50). Synthetic seismograms constructed from sonic and density logs were used along with checkshot surveys and VSP data to tie seismic horizons to stratigraphic picks made on well logs. A synthetic seismogram constructed from Blucher B-3 well logs (fig. 57) correlates fairly well with the surface seismic data and shows that there are relatively few major reflectors within the stratigraphic zone of interest. Two-way times for this zone are typically between 1350 ms and 1700 ms.

A dip-oriented section through the data volume illustrates the general structural and stratigraphic characteristics of the stratigraphic zone of interest (fig. 58). The zone below the 21B horizon at about 1700 ms shows the complexly faulted lower Frio and Vicksburg sections and clearly shows the main Vicksburg growth fault and many sets of synthetic and antithetic faults. Between the 13A and 21B horizons there is relatively little structural imprint, with the exception of a graben-like feature that intersects the 18E horizon and minor unmarked faulting in the structurally high areas.

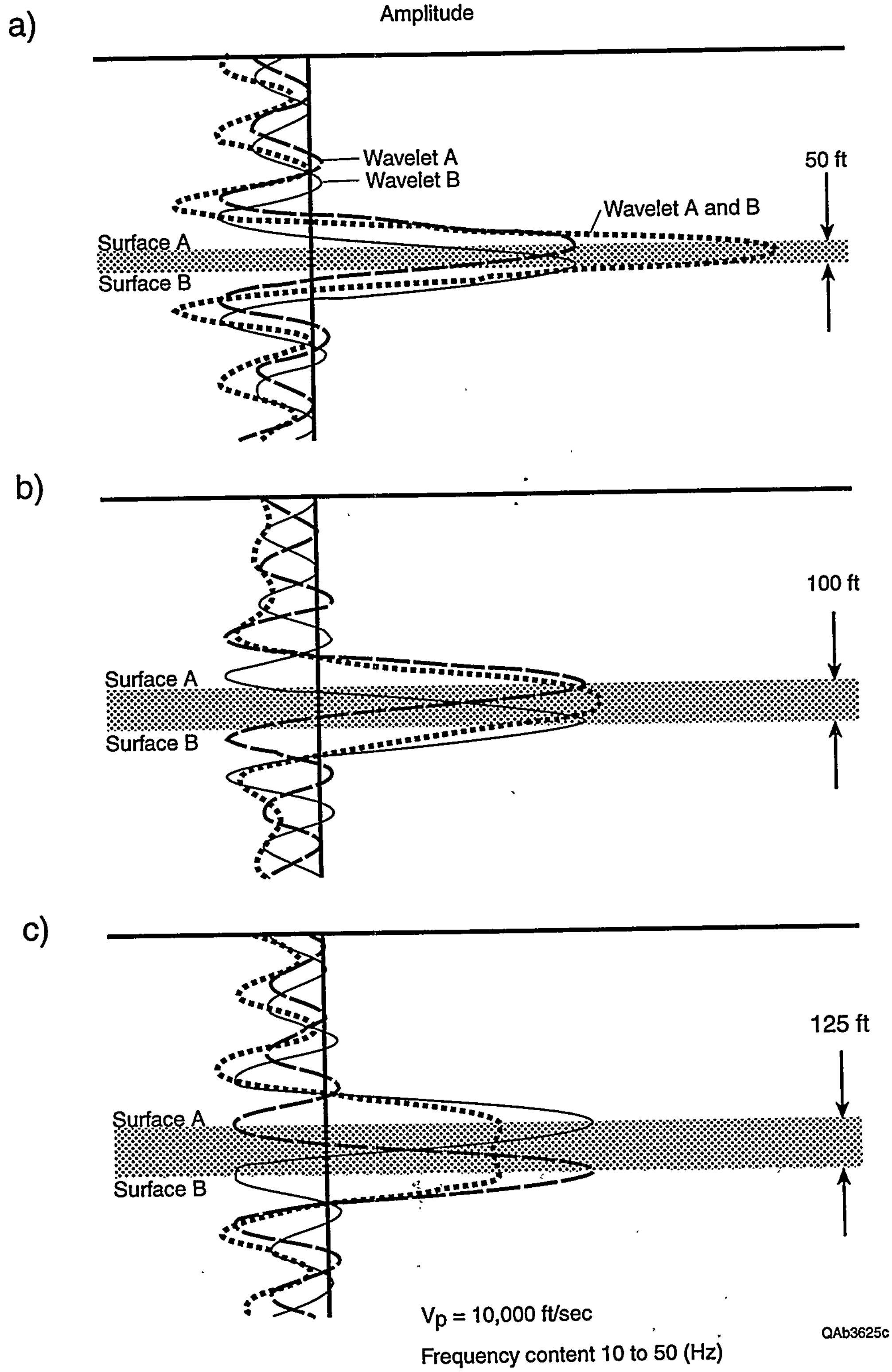


Figure 56. Effect of adding the wavelets A and B after they reflect from similar interfaces A and B that are separated by (a) 50 ft, (b) 100 ft, and (c) 125 ft. Modeled frequency content is 10 to 50 Hz and seismic velocity is 10,000 ft/sec.

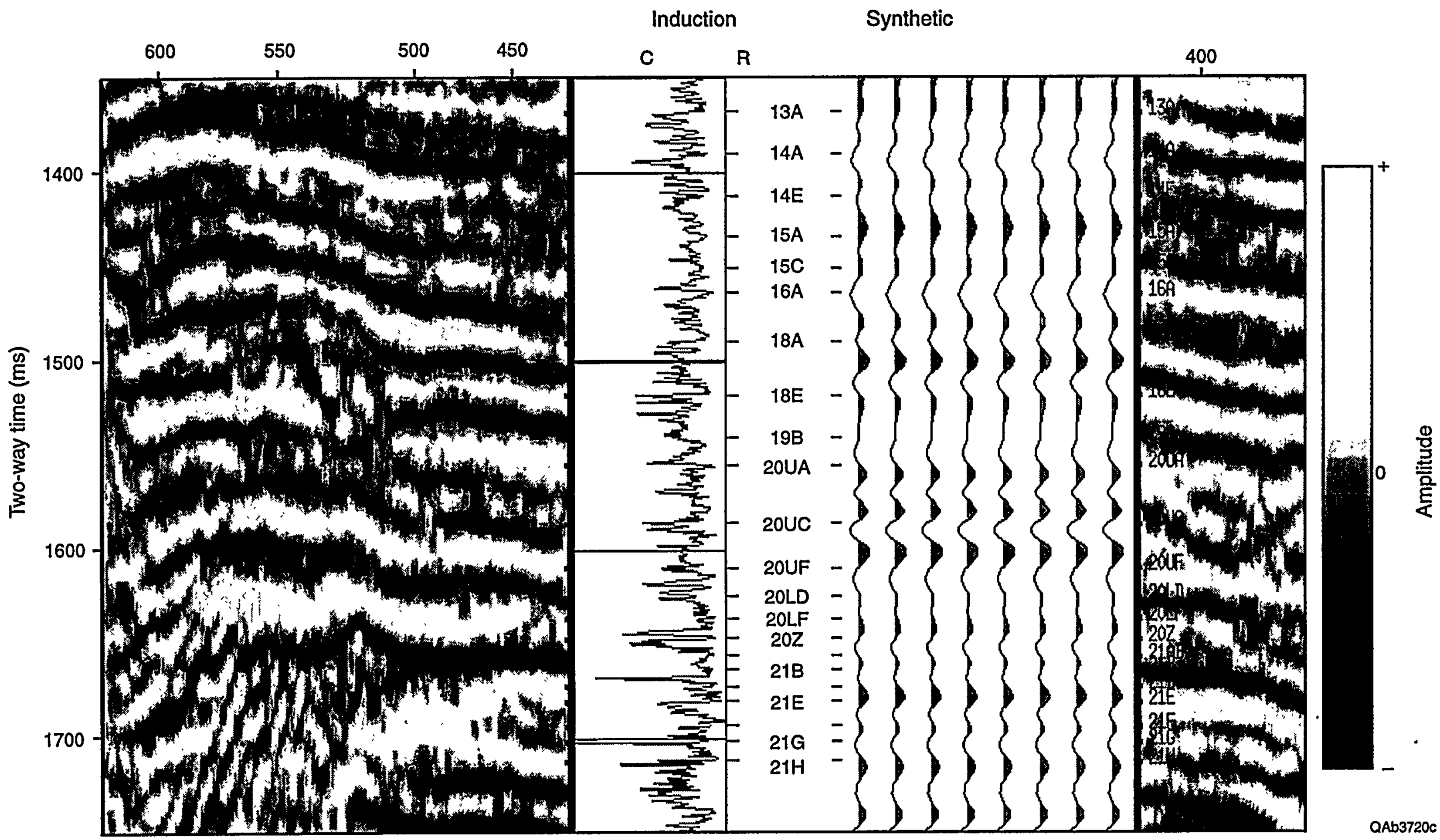


Figure 57. Synthetic seismogram constructed from sonic and density logs for the Blucher B-3 well and tied to seismic data from inline 315.

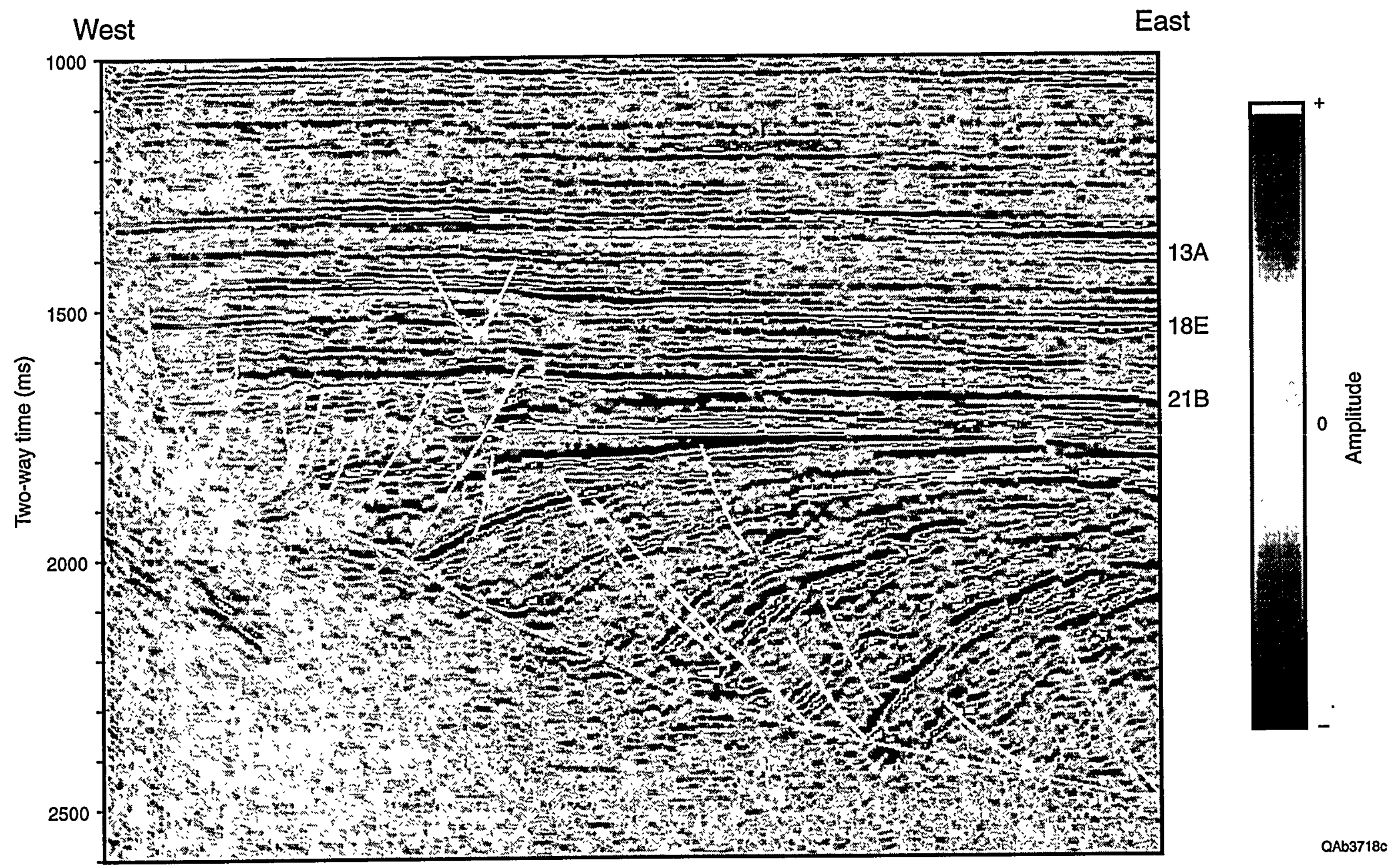


Figure 58. Representative dip line that extends east-west across the data volume. The stratigraphic zone of interest is between the 13A and 21B horizons.

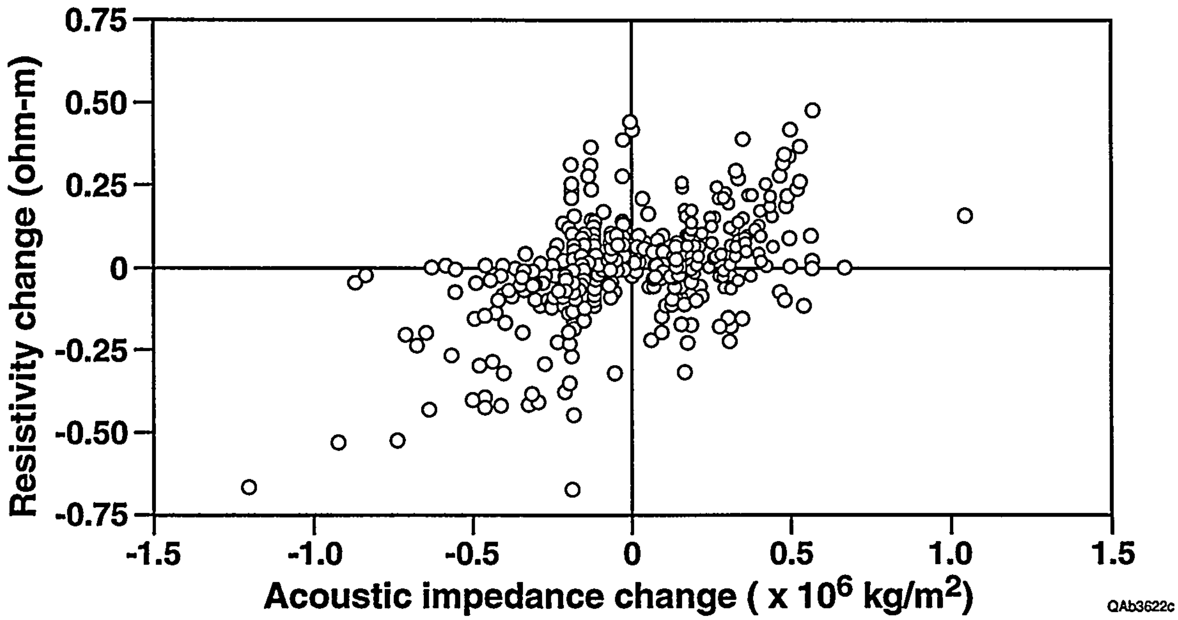


Figure 59. Downward changes in resistivity plotted against downward changes in acoustic impedance at the same well log level. Values calculated from Blucher B-3 well logs between the middle Frio Scott and Sanford intervals. Positive changes in impedance are generally accompanied by positive changes in resistivity (upper right quadrant), indicating that most positive reflections correspond to shale-to-sandstone transitions.

Lithologic source of amplitude peaks

In detailed stratigraphic reservoir analysis, it is helpful to know whether seismic amplitude peaks generally correspond to shale-to-sand or sand-to-shale transitions within the zone of interest. In the Gulf Coast region, there is much regional and vertical variation in the relative seismic velocities of shales and sands. Gamma or induction logs can be used in combination with acoustic and density logs to determine this relationship within any depth zone. For the Scott to Sanford interval within the middle Frio (fig. 50), for example, downward changes in resistivity were used as a proxy for lithology (increases in resistivity indicate increases in sand content and decreases in resistivity indicate increases in clay content). At each level where a resistivity change was calculated, an acoustic impedance (product of velocity and density) change was also calculated. These two numbers were plotted against each other (fig. 59) and show that, in general, increases in acoustic impedance correspond to increases in resistivity. In other words, seismic amplitude peaks are largely caused by the tops of sandstone bodies within this stratigraphic zone.

Further verification that amplitude peaks arise from the tops of sandstone bodies within this stratigraphic interval is obtained by converting well logs to a time scale and superimposing the logs on an arbitrary seismic section drawn through the data volume between the well log locations. Seismic section A-A' (figs. 53 and 60), an arbitrary strike section drawn from north to south through the Stewart & Jones (Ste) 1-5, Ste1-7, Blucher (Blu) 55, and Blu 37 wells, illustrates that (a) well logs are able to resolve sandstone beds far thinner than those resolvable with the seismic data, and that (b) most seismic amplitude peaks correlate with sand signatures of leftward deflection on the SP log and rightward deflection on the induction log (fig. 60). This section also shows that the power of 3D seismic data, though impressive in the vertical dimension, has its greatest advantage over well logs in the large increase in lateral resolution. Seismic units above the 13A horizon can be clearly seen to pinch out from right to left; difficult correlation problems presented by thin-bed reservoirs can be worked out more easily when arbitrary seismic lines can be constructed from one problem well to another.

Characterization Examples from the Scott/Whitehill Reservoir Interval

Genetic Stratigraphic Setting of the Scott/Whitehill Interval

A dip-oriented stratigraphic cross section stretching from several miles updip of T-C-B field to approximately 60 mi downdip (Fig. 61) was prepared so that these reservoirs could be placed within a depositional and stratigraphic framework. The character of spontaneous potential (SP) and resistivity logs was used to imply general depositional setting of Frio units in the cross section and identify shales that represented major (third- and fourth-order) marine flooding events in the downdip marginal marine setting. Log markers that bound the Scott/Whitehill reservoir interval above and below were correlated from an implied upper delta-plain position at T-C-B field to fourth-order marine flooding surfaces in the downdip area (Fig. 61). Thus, because the interval is bounded above and below by the nonmarine equivalent of flooding surfaces, it reflects a cycle of deposition beginning with progradation, leading to aggradation, and terminating with retrogradation.

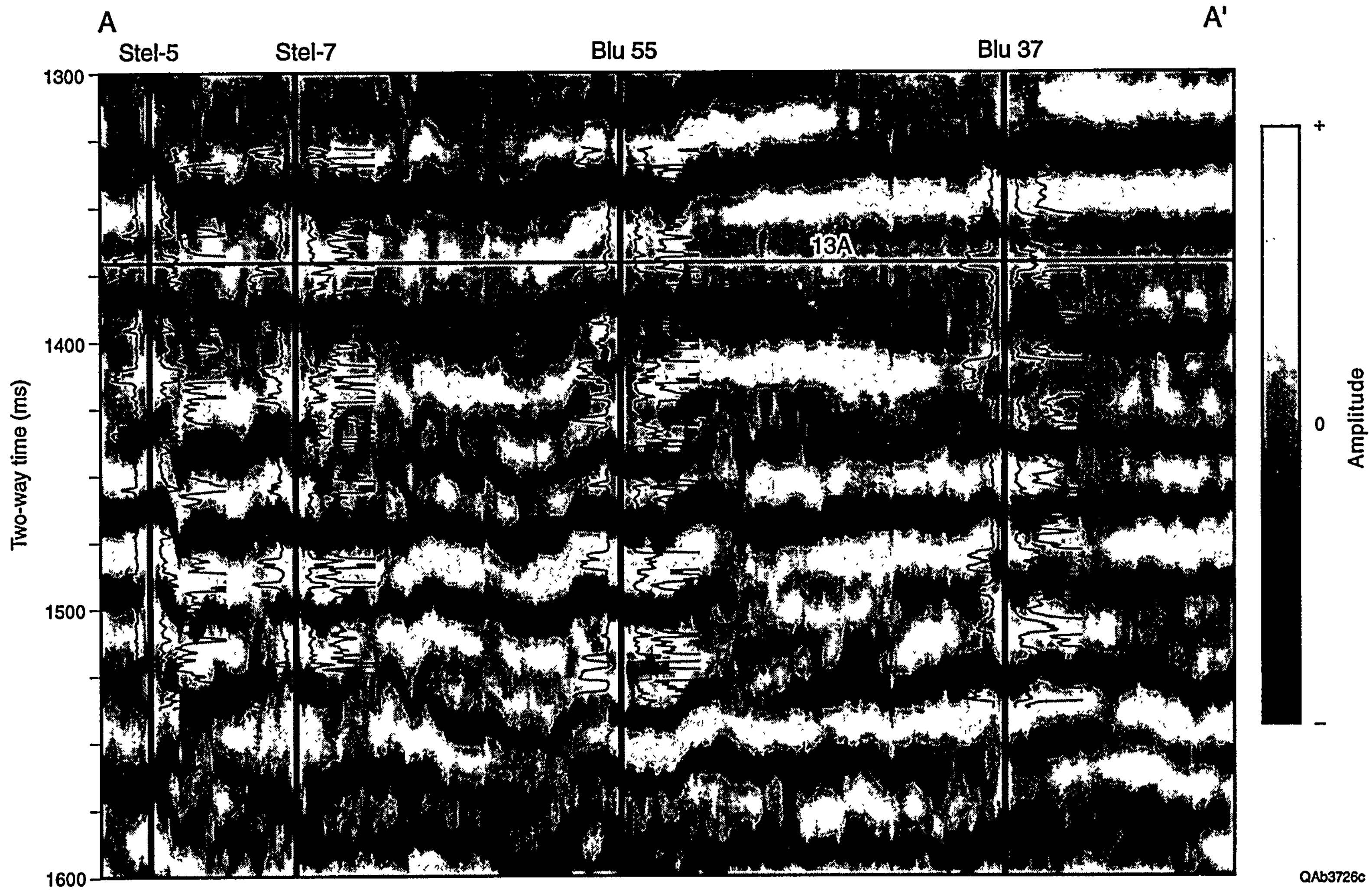


Figure 60. Arbitrary seismic strike section A–A′ with overlain time-converted well logs from the Stewart-Jones 1-5, Stewart-Jones 1-7, Blucher 55, and Blucher 37 wells. Data are flattened on the 13A seismic horizon.

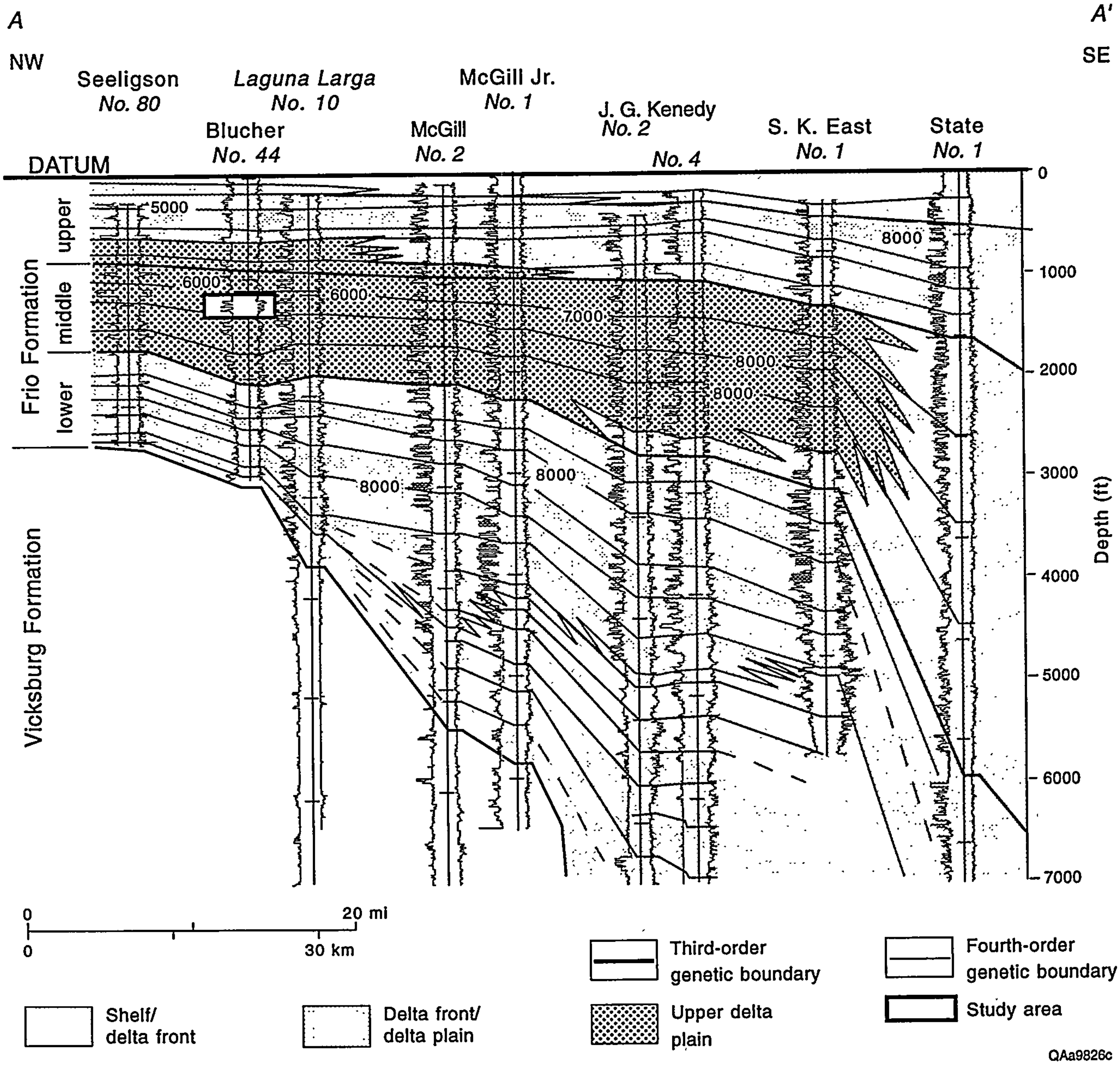


Figure 61. Dip-oriented stratigraphic cross section A–A′ through the Frio Formation from updip of T-C-B field down to the present coastline. The Frio consists of three 3rd-order depositional units, each containing 4th-order units. See Figure 49 for location of cross section.

Architecture of Reservoirs within the Scott/Whitehill Depositional Cycle

The general stratigraphy and architecture of the Scott/Whitehill reservoir interval can be deduced from careful well log correlation, and are shown in a dip-oriented stratigraphic cross section through the study area (Fig. 62) and a series of net sandstone maps (Fig. 63b,c, and d). The interval is divided into four fifth-order genetic units by laterally continuous surfaces that

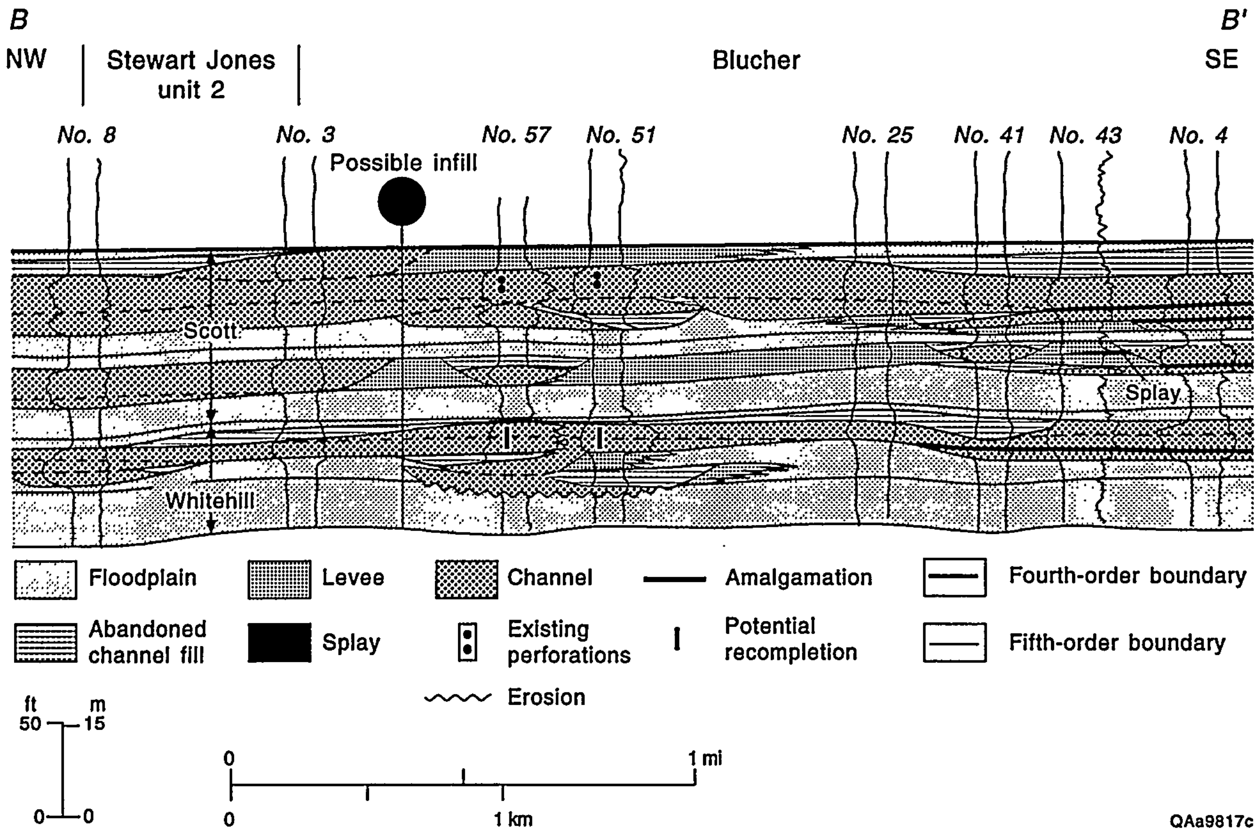


Figure 62. Dip-oriented stratigraphic cross section B–B′ of the Scott/Whitehill 4th-order reservoir interval, which contains at least four 5th-order depositional cycles. These are, from the top down, the upper and lower Scott and the upper and lower Whitehill reservoir intervals. See Figure 63a for location of cross-section.

may correspond to more minor marine flooding events. Narrow to broad dip-oriented channel belts represent major reservoir compartments. Each fifth-order genetic unit ranges in thickness from 20 to 50 ft, with each successive unit generally thickening from the lower Whitehill 20 ft at the base through the upper Scott (50 ft) (Fig. 62) at the top. Assuming equivalent time spans for each unit, this would suggest persistently increasing rates of accommodation. In addition, the percentage of net sandstone also increases upward.

Sandstones within the Scott/Whitehill interval are draped across a subtle south-plunging structural nose (Fig. 63a). They display symmetrical, blocky, or upward-fining log patterns, range in thickness from 3 ft to more than 50 ft, and are separated by siltstones and mudstones of similar thickness. Thicker sandstones consist of amalgamated individual channel deposits, each of which

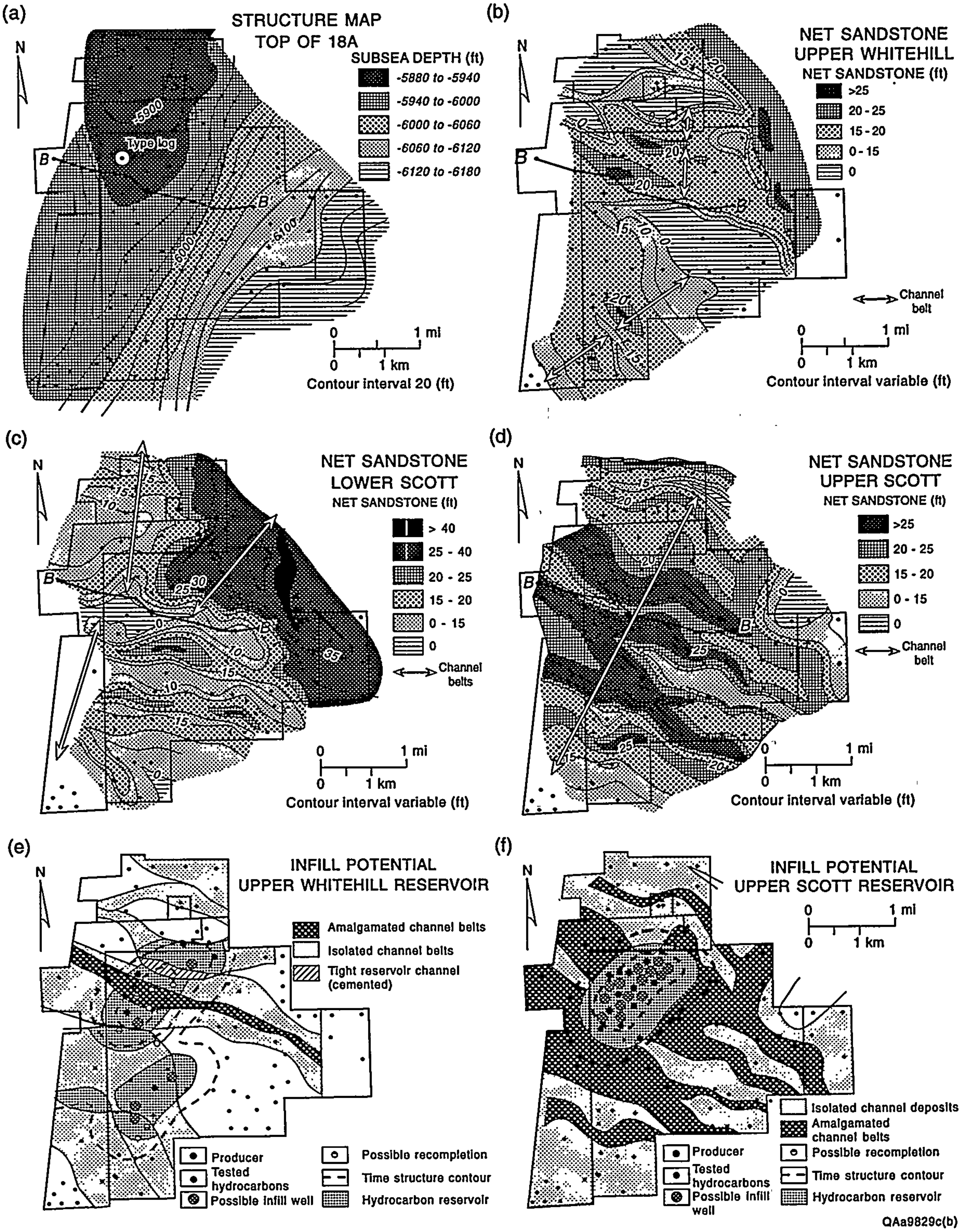


Figure 63. Structure, net sandstone, and infill-potential maps, Scott/Whitehill reservoirs. (a) Structure map on the 4th-order flooding surface that forms the upper boundary of the interval. Cross section B–B′ shown in Figure 62. (b) Net-sandstone map of the upper Whitehill 5th-order interval. (c) Net-sandstone map of the lower Scott 5th-order interval. (d) Net-sandstone map of the upper Scott 5th-order interval. (e) Infill potential map of the upper Whitehill reservoir interval. (f) Infill potential of the upper Scott reservoir interval.

reaches a maximum of 20 ft. The dominance of a blocky and upward-fining log pattern, the absence of microfauna, and the regional setting all indicate that these sandstones were deposited in an upper delta-plain fluvial setting. Depositional facies identified on the basis of log character include sandy point bar channel deposits, silty to muddy abandoned channel fill, rare sandy splay deposits, silty levee deposits, and fine-grained floodplain mudstones (Fig. 62).

The lowermost fifth-order unit, the lower Whitehill, deposited at the base of the depositional cycle (low accommodation) and therefore a seaward-stepping unit, is composed entirely of floodplain mudstone throughout the study area. Correlation in the T-C-B area shows no widespread sandstones at this level, but the existence of narrow localized deposits has not been ruled out because channel bodies might be narrower than the log spacing used for regional correlation (approximately 1 mi apart).

The overlying upper Whitehill unit, in the seaward-stepping to vertically stacked portion of the depositional cycle (low to intermediate accommodation), consists of three relatively narrow (1 mi wide) but generally thin fluvial channel-belt deposits (Fig. 63b) separated by large areas of floodplain mudstone. These channel belts trend in a general dip orientation and are typically less than 20 ft in thickness. Thicknesses in excess of this are the result of vertical stacking of broader channel belts (1 mi wide) in the middle or upper portion of the interval on top of very narrow channel belts (0.3 mi wide) at the base of the interval. The comparatively broader channel belts in the middle and upper portion are each interpreted to contain two to three incomplete, vertically amalgamated channel deposits, each ranging from 5 to 10 ft in thickness. Abandoned channel mudstones are most common in the uppermost channel deposits.

The next highest unit, the lower Scott, in the vertically stacked to landward-stepping portion of the depositional cycle (intermediate to high accommodation), is similar to the upper Whitehill except that channel belts tend to be broader (1.5 mi) (Figs. 62 and 63c). In addition, the narrow channel belts that occur at the base of the interval are restricted to the northeastern portion of the study area, where an unusually thick accumulation of channel deposits may have resulted from subtle paleotopographic control. Overall, the lower Scott contains a greater volume of sandstone than the underlying upper Whitehill interval.

The upper Scott reservoir interval, at the top of the fourth-order unit and, thus, in the strongly landward-stepping portion of the depositional cycle (high accommodation), differs markedly from the underlying intervals in that it is distinctly thicker and sandier, with a single broad channel belt (3.5 mi wide) covering the entire study area, which consists of vertically amalgamated channel deposits (Figs. 62 and 63d). Dip-oriented bodies of sandstone thicknesses in excess of 20 ft are the result of two or three vertically amalgamated channel deposits, each separated from the other by abandoned channel mudstones, finer grained upper channel-fill deposits (presumably rippled silty sandstones of an upper point bar setting), or possibly thin layers of mudclast rip-up conglomerate at the bases of channels. The uppermost portion of the upper Scott interval is dominated by siltstones and mudstones of abandoned channel, levee, and floodplain deposits (Fig. 62).

In summary, from the lower Whitehill at the base of the fourth-order depositional cycle (lower accommodation) to the upper Scott at the top (highest accommodation), there is a progressive change in channel architecture and heterogeneity. Individual fifth-order units become thicker upward, and net sandstone percentage increases. Channel belts become wider in each stratigraphically higher unit, and greater volumes of fine-grained channel-fill deposits, such as upper point bar and abandoned channel fill, are present in successively higher units. These features closely correspond to observed accommodation-dependent architecture in the Ferron distributary channel deposits.

Geophysical Identification of Scott/Whitehill Architecture

The identification of reservoir architecture using only well data requires the extrapolation of sandstone body geometries between wells. The accuracy of this extrapolation is dependent upon the predictability inherent in geologic models and is limited by a lack of information between well control. The stratigraphic interpretation of 3-D seismic data can improve the identification of reservoir architecture by imaging compartment boundaries between well control.

To analyze the architecture of reservoirs in the Scott/Whitehill interval, the extensive shale above the Scott, correlative to a 4th-order flooding surface, was picked in the seismic data and the

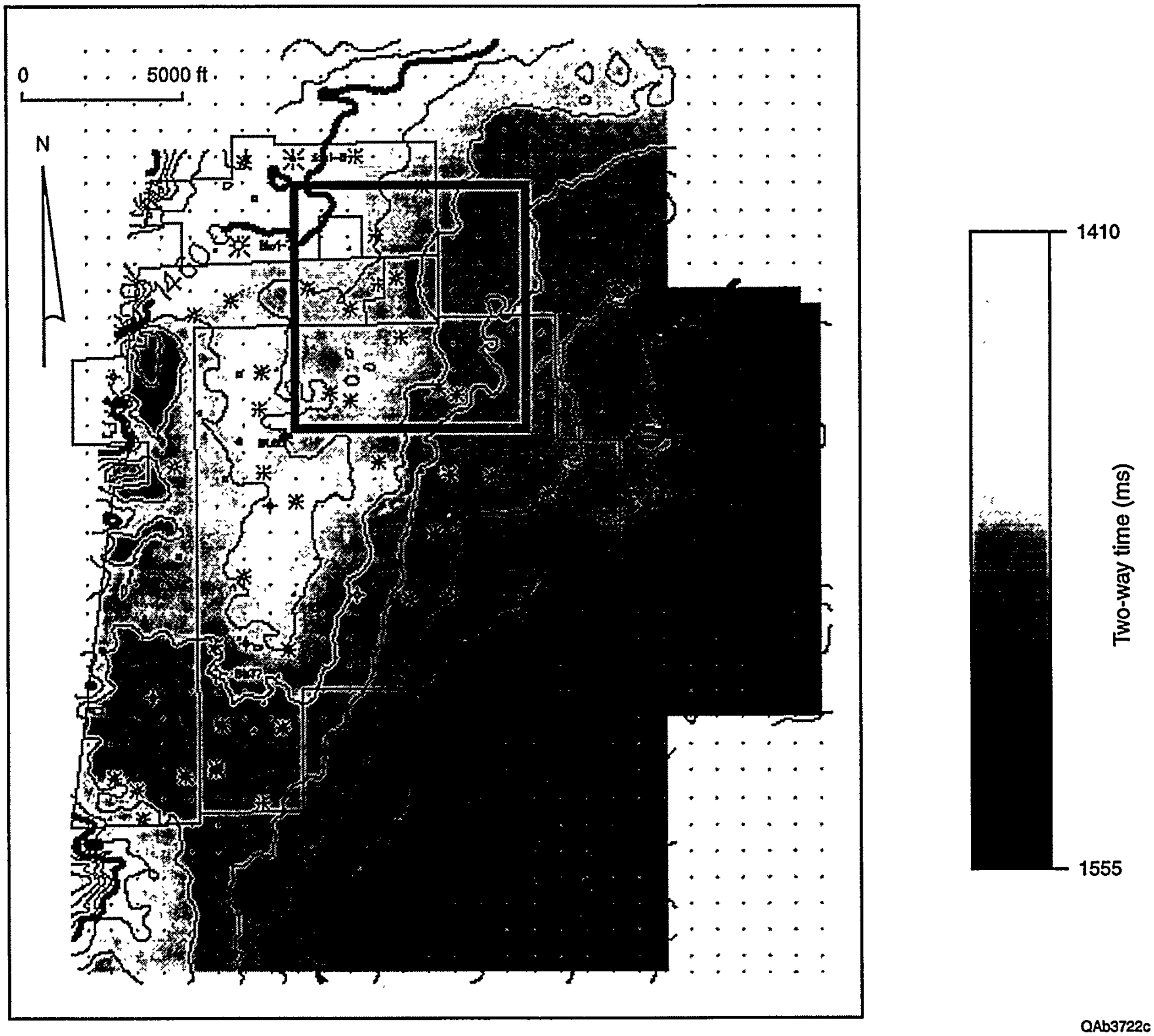


Figure 64. Upper Whitehill structure map in two-way time. Box represents area covered by Figures 65 and 66.

volume flattened on this horizon. Amplitude values across the study area were then sampled at 2 ms intervals (equivalent to approximately 10 ft in depth) below the flattened horizon, a process referred to as horizon slicing. At many horizons within this interval the combination of low frequency content and insufficient seismic contrast between sandstones and shales obscured compartment boundaries. However, detailed analysis in selected areas was successful in clarifying between-well architecture.

An example of this analysis is from the upper Whitehill interval. Figure 64 is a structural map in time on a seismic horizon closest to this stratigraphic interval and shows a north-

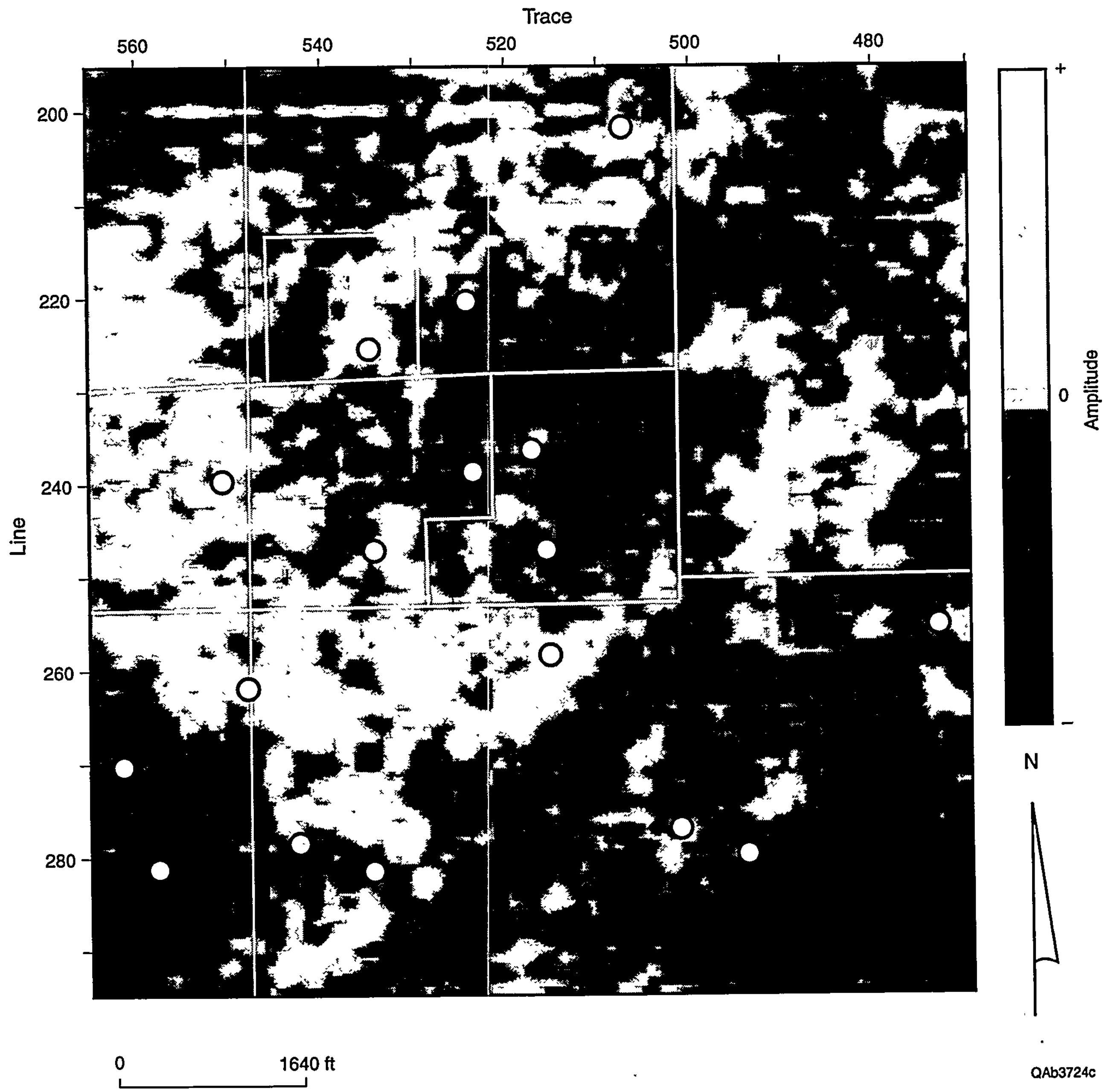


Figure 65. Amplitude display of time slice within the Upper Whitehill interval at 1508 ms (about 6,300 ft deep). See Figure 64 for location.

northeasterly striking high and a marked deepening to the southeast. Relatively little faulting is evident at this level. An amplitude map (horizon slice) of a 1 mi^2 area (Figure 65) at a two-way time of 1508 ms (about 6300 ft deep) shows the 2,000 ft wide feature that trends southeastward from the left side of the map and then bends northeastward in the bottom half of the map. This feature corresponds fairly well with a similar arcuate channel-like sand body as much as 25 ft thick that was mapped solely on the basis of well log patterns (fig. 66). A dominance of lower

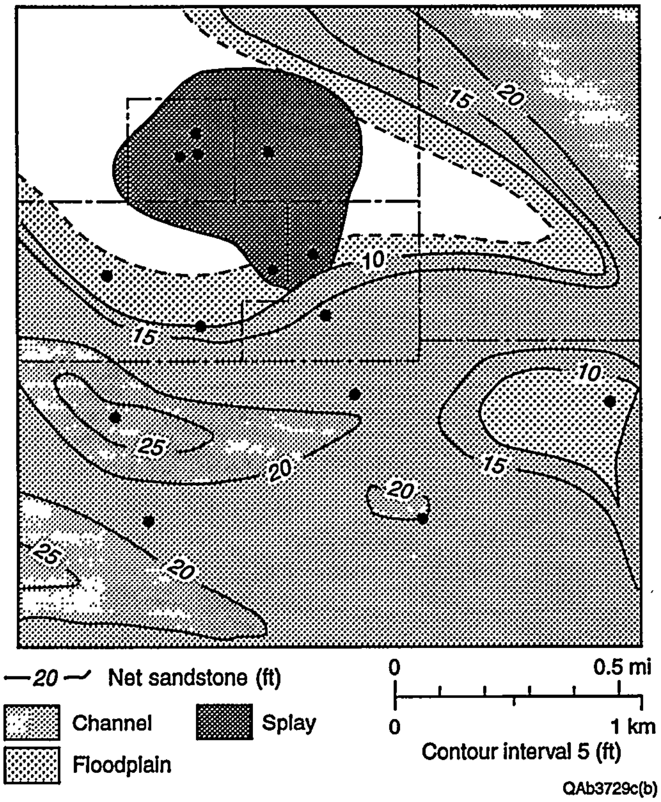


Figure 66. Net sandstone and facies map for the Upper Whitehill interval derived from log data alone. Map covers the same area as the horizon slice in Figure 65.

amplitudes in an area in the center of the northern portion marks an area interpreted as a splay from wells logs. An area to the north that was conservatively predicted from well logs to contain floodplain facies is seen to have high amplitudes in the horizon slice. This suggests that this area may instead contain a separate channel belt not encountered by well control. This increases the area of potential reservoir facies and opens up possibilities for infill potential.

Scott/Whitehill Internal Heterogeneity

Whereas the gross architecture of the reservoir compartments (channel belts) could be identified with reasonable accuracy with well log control, and augmented by 3-D seismic data, the heterogeneity within compartments is potentially much finer than the spacing between wells and is commonly beyond the resolution of seismic, being, as it likely is, controlled by the boundaries between individual channelforms. In a subsurface setting, the most reliable measure of internal heterogeneity is production performance. The relative size of areas drained in a series of reservoirs will be a measure of the internal complexity of the reservoirs, assuming similar drive mechanisms and fluid viscosities.

We have produced compartment history maps (Figs. 63e, f) for the upper Whitehill and upper Scott intervals, documenting compartment boundaries and past completions. The following discussion summarizes the production history of the two reservoirs and estimates drainage areas for these completions.

Well control, limited 2-D seismic data, and interpretations of 3-D seismic indicate two areas of subtle structural closure (Fig. 63e) on the more prominent structural nose (Fig. 63a) in the study area. Production from the Scott/Whitehill interval is limited to gas in the upper Whitehill and oil in the upper Scott.

The upper Whitehill has produced from two wells, one on the northern structural crest and the other farther to the north in which perforations were structurally below the documented gas/water contact on the structural crest (Fig. 63e). Resistivity measurements indicate moderate gas saturations in the southern structure, but no tests of this potential accumulation have been made. Mapping of channel belts and evidence of tightly carbonate cemented sandstone in one well suggest that the northernmost of the two completions was stratigraphically isolated from the structural crest. Evidence from wells postdating production indicates that the crestal completion drained approximately 40 acres. At present, insufficient data are available on the other well to document drainage area.

Eight wells have produced oil from the upper Scott on the main structural crest (Fig. 63f). Cumulative production has ranged from less than 1,000 bbl to more than 54,000 bbl per well (Table 14). Initial water cuts have varied widely and have been independent of structural position and offset production history, indicating a lack of communication between well locations (Table 14, Fig. 67). Approximate volumetric analyses suggest that completions have drained areas ranging from less than 1 acre to approximately 5 acres, significantly less than the completion in the Whitehill. Calculations indicate that despite completion at a 20- to 40-acre spacing, and the fact that all current completions are idle or nearly watered out, less than 10 percent of the original oil in place has been recovered from the Scott.

Table 14. Initial potential and cumulative production data for completions within the upper Scott zone.

Well no.	Comp. date	Initial potential	Top Scott (ft, subsea)	Cum. prod.
3	9/64	40 bwpd 129 Mcfd	-5933	squeezed
26	3/89	400 bwpd 400 Mcfd	-5959	squeezed
28	4/85	223 bopd 3 bwpd 281 Mcfd	-5929	54,608 bo 546,860 bw 181.6 MMcf
46	9/69	27 bopd 130 bwpd	-5929	18,773 bo 170,642 bw 87.1 MMcf
48	1/71	20 bopd 309 bwpd	-5939	11,499 bo 212,712 bw 51.2 MMcf
51	1/86	31 bopd 33 bwpd 403 Mcfd	-5943	3,485 bo 56,307 bw 67.8 MMcf
52	7/86	55 bopd 130 bwpd 114 Mcfd	-5932	8,641 bo 28,859 bw 71.5 MMcf
55	3/86	55 bopd 45 bwpd 127 Mcfd	-5940	12,989 bo 209,112 bw 88.9 MMcf
56	9/86	7 bopd 16 bwpd 21 Mcfd	-5952	856 bo 10,260 bw 26.3 MMcf
57	9/86	52 bopd 2 bwpd 288 Mcfd	-5935	12,273 bo 201,174 bw 86.5 MMcf

Although some of the discrepancy in recoveries from the Whitehill and the Scott can be attributed to the different mobility ratios of oil and gas, a significant part can be attributed to smaller compartment sizes in the Scott zone. This indicates that the upper Scott channel belt (high accommodation) is much more internally heterogeneous than the upper Whitehill channel belts (low to intermediate accommodation).

Reserve-Growth Opportunities

Because of sparse past development of the upper Whitehill interval, numerous recompletion opportunities exist, in addition to possible infill locations. Figure 68 shows the location of 16

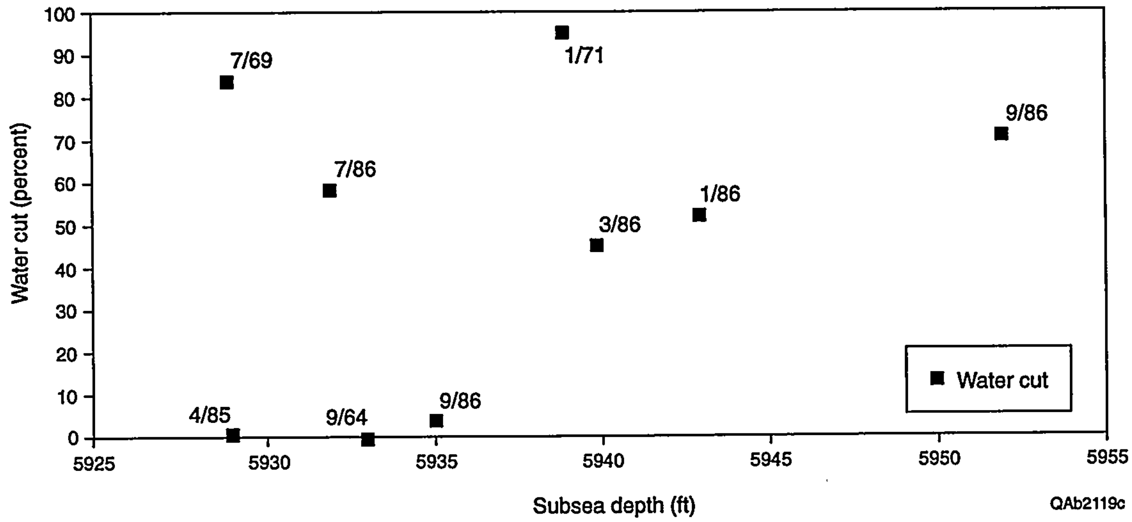


Figure 67. Crossplot of initial water cut versus depth to top of reservoir, upper Scott zone. The completion date is also annotated to document the possible effects of offset production. Note the very poor correlation of water cut versus depth or completion date, indicating laterally isolated compartments.

recompletion opportunities, which are listed in Table 15 and accompanied by a qualitative risk value and 5 infill drilling opportunities. The operator recently recompleted one well rated as moderate risk because of its proximity to a well that has produced 5 billion cubic feet (Bcf) of gas from the upper Whitehill. The recompleted well flowed moderate amounts of gas (500 Mcfd) but also is producing high volumes of water (200 bpd). The present rate is economic, despite the high water production. Three low-risk recompletions remain untested owing to a number of operating considerations such as current production from other zones in prospective wellbores. Because the drive mechanism in the upper Whitehill is a combination pressure depletion/water drive, cumulative production for proposed recompletions is anticipated to approach but not exceed 5 Bcf for each low-risk recompletion. Risk for identified infill opportunities has not been assigned, pending results of recompletions.

Because of the greater internal heterogeneity within the upper Scott interval, reserve-growth opportunities are more problematic than those in the upper Whitehill. One low- to moderate-risk recompletion exists in Blucher 59, which has excellent resistivity with the top of the reservoir at –5933 ft subsea. Most completions in which the sandstone top occurred above –5940 ft accumulated in excess of 10,000 bo, which would justify the costs of a recompletion. The

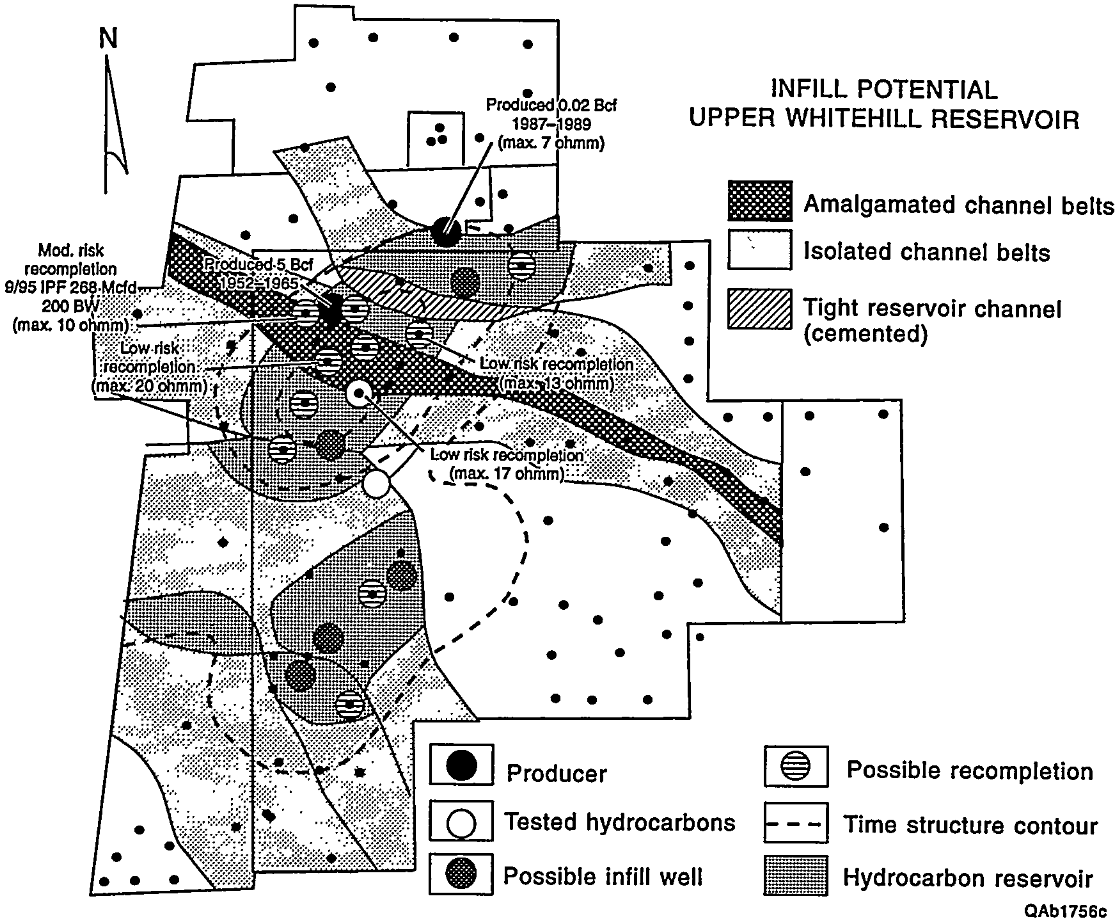


Figure 68. Map showing reservoir compartment distribution, productive limits, identified recompletion/infill opportunities, and results of one recompletion within the upper Whitehill reservoir of T-C-B field. Three recompletion opportunities evaluated as having lower risk than the current recompletion are annotated.

remainder of the opportunities in the upper Scott include 14 infill well locations. Completions on a spacing as close as 10 acres are justified on the basis of past completion performance, and each should accumulate more than 10,000 bo if it is above –5940 ft. However, such small volumes would not, by themselves, justify the cost of a new wellbore. Creative solutions are required to produce the large volume of oil remaining in the upper Scott. If other targets can be found in other reservoirs above or below the Scott that coincide with Scott infill locations, the economics of a wellbore can be improved. Alternatively, a horizontal well that contacts a larger area, perhaps draining several individual channelforms, might prove economically viable. Without more information regarding the location of individual channelform boundaries, this approach will

Table 15. Summary of recompletion opportunities in Whitehill reservoir, T-C-B field.

Well	Evidence of Productivity	Well Status	Risk
Blucher 28	Strong log show (16 ft @ >5 ohm-m, peak of 13 ohm-m)	Open to below Whitehill (producing from Scott zone at 10 bopd)	Low
Blucher 51	Very strong log show (16 ft @ > 5 ohm-m, peak of 17 ohm-m)	Open to below Whitehill (idle in Sanford)	Low
Blucher 57	Good resistivity (22 ft @ > 5 ohm-m, peak of 20 ohm-m), 16% porosity, suppressed SP suggests tight but microlog indicates 8 ft of permeable reservoir	Open to below Whitehill (idle in Scott)	Low
Blucher 32	Strong Log show (12 ft @ > 5 ohm-m, peak of 7.5 ohm-m)	Open to below Whitehill (producing from Richard zone, 50 Mcfd)	Low-Moderate
Blucher 1	Strong log show (15 ft @ > 5 ohm-m, peak of 15 ohm-m)	Open to below Whitehill (idle in Imme zone)	Moderate
Blucher 23	Strong log show (11 ft @ >5 ohm-m, peak of 6.5 ohm-m)	Open to below Whitehill (idle in 21-B)	Moderate
Blucher 42	High resistivity in thin bed (5 ft @ > 3 ohm-m, peak of 4 ohm-m)	Idle (Stray, 6030'), 4 plugs above Whitehill	Moderate
Blucher 55	High resistivity (9 ft @ > 5 ohm-m, peak of 8.5 ohm-m) but low porosity (5 ft < 12%)	Open to below Whitehill (idle in Charles)	Moderate
Blucher 58	High resistivity (3 ft @ > 5 ohm-m, peak of 6 ohm-m), 18% porosity, RWA curve indicates 4 ft pay	Open to below Whitehill (producing X from Carl)	Moderate
Blucher 59	Strong log show (20 ft @ > 5 ohm-m, peak of 10 ohm-m)	Open to below Whitehill (idle in Charles)	Moderate
Seeligson 7	High resistivity (5 ft @ > 5 ohm-m, peak of 5.5 ohm-m)	Open to below Whitehill (producing X from Alexander)	Moderate
Blucher 25	High resistivity (10 ft @ > 4 ohm-m, peak of 4.5 ohm-m)	Open to below Whitehill (producing X from Charles)	Moderate-High
Blucher 43	High resistivity (3 ft @ > 5 ohm-m, peak of 5.2 ohm-m)	Open to below Whitehill (idle in Jim Wells)	Moderate-High
Blucher 50	High resistivity (3 ft @ 5 ohm-m), perforated and squeezed due to channeling	Open to below Whitehill (idle in Richard)	Moderate-High
Blucher 52	High resistivity (4 ft @ > 5 ohm-m, peak of 6 ohm-m), 18% porosity	Open to below Whitehill (idle in Arguellez)	Moderate-High
Blucher 53	High resistivity (7 ft @ > 5 ohm-m, peak of 6 ohm-m), 2 ft of weak RWA show	Open to below Whitehill (idle in Nicholas)	Moderate-High

contain significant technical risk. However, if the current recovery percentage of less than 10 percent of the original oil in place could be improved, through geologically targeted horizontal drilling, to just 20 percent, more than 0.5 million barrels of reserves could be added.

Accommodation-Based Predictive Model for Reserve-Growth Potential in Upper Delta-Plain Fluvial Reservoirs

Data from subsurface reservoirs in the Frio Formation, T-C-B field, deposited in an upper delta-plain fluvial setting, document a correlation between the reserve-growth potential of mature reservoirs and reservoir architecture and internal heterogeneity, which appear to be related to position within a depositional cycle. Outcrop observations of the Ferron Sandstone supply additional evidence that architecture and internal heterogeneity are a function of rate of accommodation, which varies predictably throughout a depositional cycle. This correlation could provide a powerful predictive tool for assessing reserve growth potential and improving the confidence of reservoir characterization studies. To better explain the hypothesized link between accommodation rate, architecture, internal heterogeneity, and reserve-growth potential in upper delta-plain fluvial reservoirs, the following section summarizes the interpreted sequence of events affecting the reserve-growth potential of reservoirs in the Scott/Whitehill interval during the course of a single depositional cycle.

Figure 69 illustrates the progression envisioned for the Scott/Whitehill succession of the upper delta plain. Figure 69a represents the upper portion of the sequence underlying the Scott/Whitehill, deposited near maximum relative sea-level highstand and under conditions of high accommodation. Frequent avulsion and meandering create a series of laterally and vertically amalgamated channels within one broad channel belt.

As sea level begins to fall, resulting in decreasing accommodation, the delta steps seaward, lengthening and straightening the fluvial system and creating a single, potentially incised, channel belt containing internally homogeneous sandy deposits (Fig. 69b). This is flanked by a broad, slowly aggrading floodplain that receives overbank muds during flood events. This stage

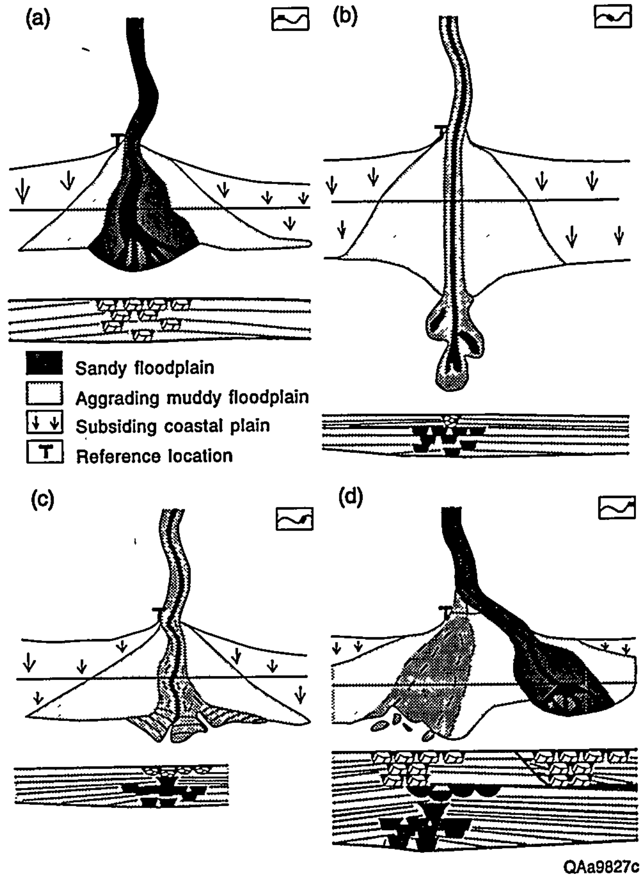


Figure 69. Model for upper delta-plain fluvial architecture under the range of accommodation conditions experienced during a depositional cycle. (a) High accommodation at maximum highstand of relative sea level results in a series of heterolithic vertically and laterally amalgamated channels. (b) Low accommodation during falling relative sea level results in a single internally homogeneous channelbelt. (c) Slightly higher accommodation during initial rise of relative sea level results in occasional avulsion and a series of laterally isolated internally homogeneous channelbelts similar to those in the upper Whitehill. (d) Highest accommodation during maximum rate of rise of relative sea level again results in a single broad heterolithic channelbelt similar to that in the upper Scott reservoir interval. This is also a period during which the fluvial system may be prone to major avulsion and switching of the deltaic depocenter.

corresponds to the deposits of the lower Whitehill, which are dominated by mudstone but may include a single primary channel deposit located outside the study area.

During initial sea-level rise (Fig. 69c), minor accommodation in the upper delta-plain results in infrequent major avulsion events, leading to the deposition of few laterally isolated channel belts. Within channel belts, the limited accommodation results in scouring and removal of much of the upper portion of most individual channel deposits. This is similar to the setting of the upper Whitehill reservoir interval and produces reservoir compartments that correspond to channel belts, laterally isolated but internally homogeneous. As in the upper Whitehill, such reservoirs can be drained effectively by larger well spacings, but infill well locations should be selected so as to avoid the broad areas of floodplain that separate channels. Also, the potential for off-crest stratigraphic accumulations should be considered.

When relative sea level is rising at a maximum rate, the rate of generation of accommodation is also greatest (Fig. 69d). Lateral channel migration and frequent avulsion result in a broad channel belt composed of many vertically and laterally amalgamated channel deposits. However, because of the preservation of finer grained upper channel and abandoned-channel-fill deposits and the abundance of low-permeability mudclast-rich basal lag deposits, the resulting reservoir deposit will be internally heterogeneous, with many barriers to fluid flow at sandstone-on-sandstone contacts.

It should be noted that observations of the Quaternary deposits of the Colorado River of Texas (Blum, 1990) suggest that periods of high accommodation may represent times when major avulsion of a fluvial system occurs, resulting in substantial shifting of the locus of deltaic deposition. The upper Scott reservoir was deposited under such conditions of high accommodation. Here, sufficient permeability between individual channel deposits exists to allow the reservoir to have a common oil/water contact because it filled over geologic time. However, enough permeability barriers or baffles exist that, over the comparatively shorter period of reservoir depletion, the reservoir responds as though it were composed of a number of isolated compartments.

In summary, a spectrum of reservoir styles exists within the upper delta-plain deposits of the Frio Formation in T-C-B field (Fig. 70). This spectrum is the result of varying amounts of accommodation during the period of deposition of the reservoir sandstones. Reservoirs range from moderately narrow, internally homogeneous channel belts deposited under conditions of low accommodation in the seaward-stepping portion of a depositional cycle to broad internally heterogeneous channel belts laid down under conditions of high accommodation in the landward-stepping phase of a depositional cycle. These reservoir styles contain varying reserve-growth potential and require very different strategies for optimum development. In general, upper delta-plain fluvial reservoirs deposited during a landward-stepping period contain the greatest reserve-growth potential and may require the tightest well spacings for optimal reservoir drainage.

A Cautionary Note

Changing fluvial style in the upper delta plain during a depositional cycle results in a pattern of upward-increasing net sandstone percentage. However, opposite patterns have been observed in the lower delta plain, where observations suggest that the highest percentage of sandstone is deposited during the lowstand. In explanation, one hypothesis is that during the early period of relative sea-level rise, fluvial gradients, which have not fully equilibrated with the rapidly rising base level, and initial backstepping of the delta favor sand deposition and preservation in the lower delta plain. During the later rising phase, deposition and preservation shift to the upper delta plain.

Uses of the Model

The model represents a significant breakthrough in reservoir characterization in that it is an inexpensive, flexible, predictive tool that is simple enough to use in a quick-look estimate of reserve-growth potential but powerful enough to guide a detailed reservoir characterization study. By placing reservoirs into a sequence stratigraphic framework of depositional cycles, the model provides rules that allow predictions of between-well architecture and sandstone continuity, degree of compartmentalization, and intracompartment heterogeneity. This tool effectively bridges the gap between routine reservoir characterization made on the basis of well-log correlations and more expensive methods utilizing stratigraphic analysis of 3-D seismic data. Specific uses include (1) estimation of relative reserve-growth potential of a group of reservoirs, leading to prioritization of these reservoirs for detailed characterization studies and (2) risk reduction of reservoir development activities through more confident understanding of reservoir complexities.

The model is an integral component of a quick-look analysis of reserve-growth potential. Reservoirs are placed within a framework of depositional cycles to predict internal stratigraphic heterogeneity. Other factors, such as initial estimates of structural heterogeneity, reservoir significance, and past completion history, are integrated. Reservoirs can then be ranked in terms

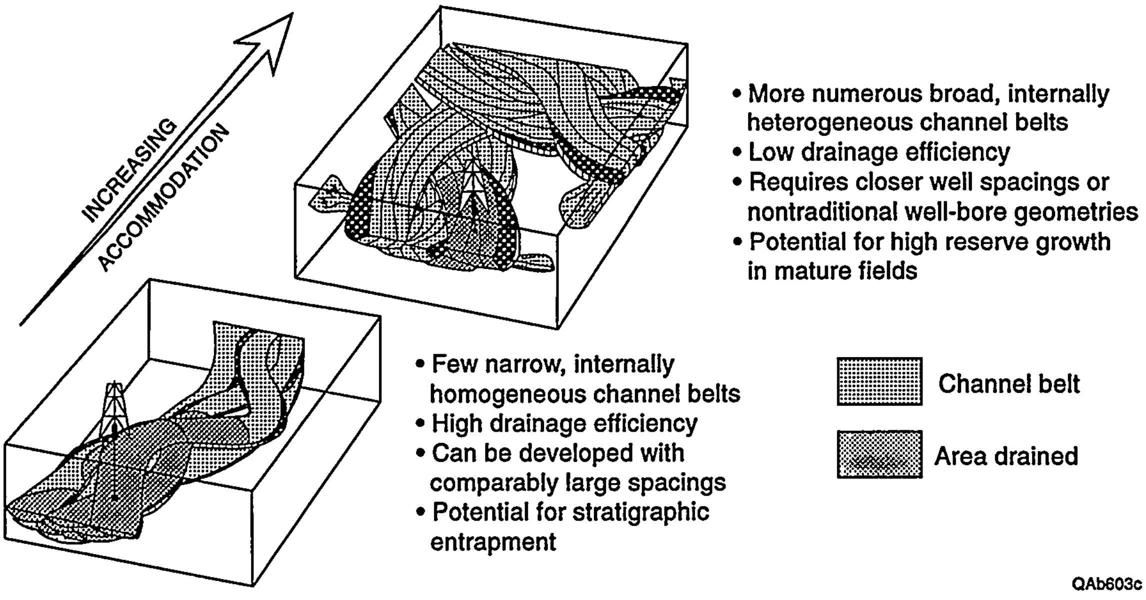


Figure 70. Spectrum of upper delta-plain fluvial reservoir architecture, internal heterogeneity, production characteristics, and reserve-growth potential encountered in the Scott/Whitehill interval.

of estimated reserve-growth potential based on this information. Significant reservoirs with sparse completions and high structural or stratigraphic heterogeneity would rank high and receive further attention to refine the estimation of reserve-growth potential. Ultimately, this leads to the informed selection of specific intervals for detailed reservoir characterization aimed at identifying the location of remaining mobile oil or gas (see Reservoir Prioritization section).

The model also provides critical assistance during detailed characterization studies by allowing a more confident interpretation of the reservoir at the between-well scale, thereby reducing the geologic risk associated with subsequent recompletions or infill drilling to target identified reserves. For example, when core material is unavailable and difficult facies interpretations and correlations must be based on log information alone, the model provides rules for the vertical progression of facies and architecture: sandstones at the base of a cycle should show a progradational architecture and contain more proximal facies than those immediately above them, whereas sandstones at the top of the cycle should show reversed relationships.

Implications

The model described here only addresses reservoirs deposited in an upper delta-plain fluvial setting. However, it represents a new generation of models for reservoir characterization. Because rates of accommodation can be demonstrated to control sandstone body architecture and internal heterogeneity, and because these effects are different for each depositional setting but can be documented from outcrop work or implied from careful subsurface study, other models must be developed for reservoirs deposited in the spectrum of depositional settings. Any such models must be based on outcrop observations because continuous lateral exposures are critical for identifying geometries and permeability characteristics of the surfaces that bound potential reservoir compartments. Further understanding of the cyclic nature of the stratigraphic record, and the controls on that cyclicity, will provide more accurate models and supply more specific guidelines for their application in various depositional settings.

The predictive nature of these new models will improve the accuracy of reservoir characterization studies and increase the use of reservoir characterization by operators of mature fields. The outcome will undoubtedly be increased recovery of oil and gas from reservoirs that otherwise might have been abandoned prematurely, preventing permanent loss of vital resources.

RESERVOIR PRIORITIZATION

P. R. Knox

The methodology of integrated multidisciplinary reservoir characterization that has been described and demonstrated in this report requires significant effort on the part of the operator. Gathering of field data and interpretation of detailed reservoir architecture and compartmentalization requires a significant commitment of time from geological, geophysical, and engineering staff, and the acquisition of seismic data and reservoir visualization software can involve a large expense. As a consequence, an initial effort should be made to insure that the reservoirs selected for detailed study have a high potential for yielding additional reserves. This effort should consist of a quick-look evaluation in which readily available parameters are used to estimate reserve growth potential and rank reservoirs from greatest to least potential.

Quick-look Evaluation Factors

On the basis of experience gained during this investigation, six factors were identified that can be used to help determine the potential for reserve growth from untapped and incompletely drained compartments in mature reservoirs. Four of these factors, (1) relative reservoir size, (2) past completion density, (3) reservoir heterogeneity, and (4) hydrocarbon mobility address the likelihood that unrecovered hydrocarbons exist in the reservoir. The two remaining factors, (5) reservoir depth and (6) operator gas/oil preference, provide indications of economic efficiency and practical company strategy.

Larger relative reservoir size indicates a greater potential for unrecovered oil because, in considering two reservoirs with equal past recovery efficiency (percentage), the larger reservoir will contain a greater volume of oil still remaining. For example, consider two reservoirs having similar characteristics except that one contains 10 MMbbl of mobile oil originally and the other 1 MMbbl originally. If 30 percent of the oil is recovered from each reservoir, the larger reservoir will still contain 7 MMbbl of mobile oil to be recovered by recompletions and infill drilling, whereas the smaller reservoir will contain only 0.7 MMbbl. It is more likely that the cost of reservoir characterization will be recouped in the course of increased production from the larger reservoir, whereas the risk of pay out will be higher for the smaller reservoir. Relative reservoir size can be evaluated from volumetric data (e.g., OOIP), if available, or estimated by comparing cumulative production of the reservoirs being ranked. The latter approach assumes that the reservoirs have had similarly thorough development and are at a similar stage of maturity.

If past completion density in a reservoir is low (well spacing is large), the potential of that reservoir for reserve growth may be high because there is a greater chance that untapped reservoir compartments exist between well penetrations. In addition, heterogeneity within compartments may limit the size of the effective drainage area, leaving substantial portions of compartments incompletely drained (Figure 71). The greater the past completion density (the closer the well spacing), the less chance that substantial areas of the reservoir remain undrained.

The higher the reservoir heterogeneity, the greater the chance that areas exist in the reservoir that are not in good communication with current well penetrations. Reservoir heterogeneity is a function of (1) structural complexity, which creates fault-bounded compartments, (2) complex stratigraphic architecture, which results in many small stratigraphically isolated compartments (e.g., channel belts), and (3) intercompartment heterogeneity, in which lithologic contrasts within an architectural unit inhibit fluid flow through a compartment (e.g., low-permeability channel-on-channel contacts) (Figure 70). Structural heterogeneity can be qualitatively deduced from existing structure maps, general structural setting, or from seismic sections or volumes. Both types of stratigraphic heterogeneity can be inferred from well log correlatability or knowledge of depositional facies and position within a depositional cycle (Figure 72). Predicting stratigraphic heterogeneity is discussed further in "Accommodation-based predictive model for reserve-growth potential" in the section covering characterization examples from T-C-B field. Table 16 provides a summary of potential heterogeneity for Gulf Coast fluvial-deltaic reservoirs.

The greater the hydrocarbon mobility, the poorer the chances of a reservoir containing significant undrained reserves, all other factors being equal between two reservoirs. Hydrocarbon

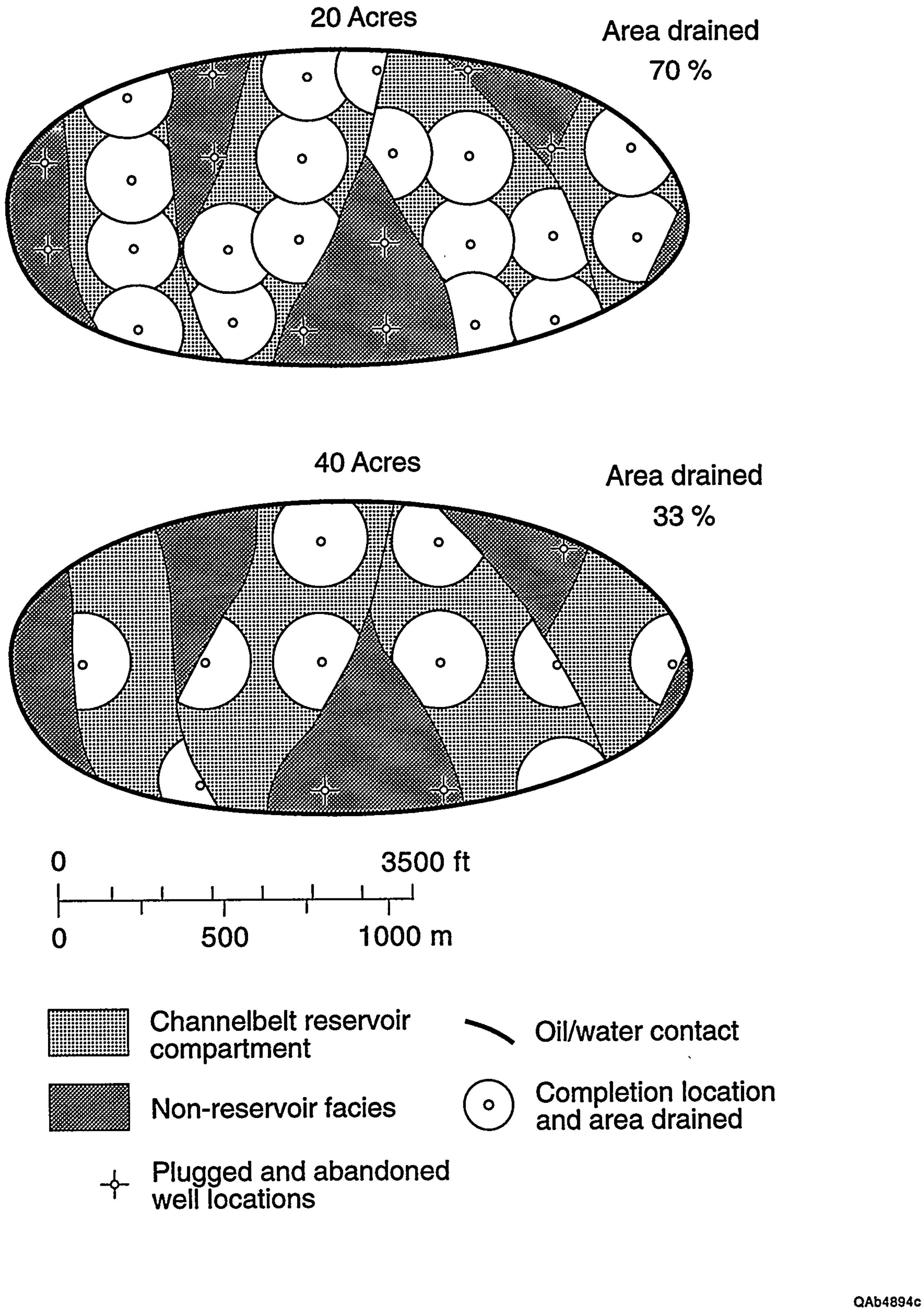


Figure 71. The effect of past completion density on reserve growth potential. All other things being equal, a reservoir developed at a closer spacing has probably been more well drained than one completed at a wider spacing.

Table 16. Potential effects on reservoir architecture of position within 4th- and 5th-order cycles.

STAGE	U. DELTA PLAIN	L. DELTA PLAIN	DELTA FRONT
LANDWARD STEPPING	THICK, BROAD, HETEROGENEOUS CHANNEL BELTS	FEWER BUT THICKER HETEROGENEOUS DISTRIBUTARIES	FEWER, THICKER CHANNEL AND MOUTH BAR DEPOSITS WITH COMMON WAVE-REWORKED TOPS
VERTICALLY STACKED	BROAD, MODERATELY THICK AND HETEROGENEOUS CHANNEL BELTS	MORE THICK HETEROGENEOUS DISTRIBUTARIES	FEWER, THICKER CHANNELS, POSSIBLY SUBORDINATE TO MOUTH BAR AND DELTA FRONT BODIES
SEAWARD STEPPING	NARROW, POSSIBLY THIN AND INCISED, ISOLATED CHANNELS	MANY BROAD SHALLOW SANDY CHANNEL BELTS?	MANY LONG NARROW SANDY CHANNEL AND MOUTH BAR DEPOSITS

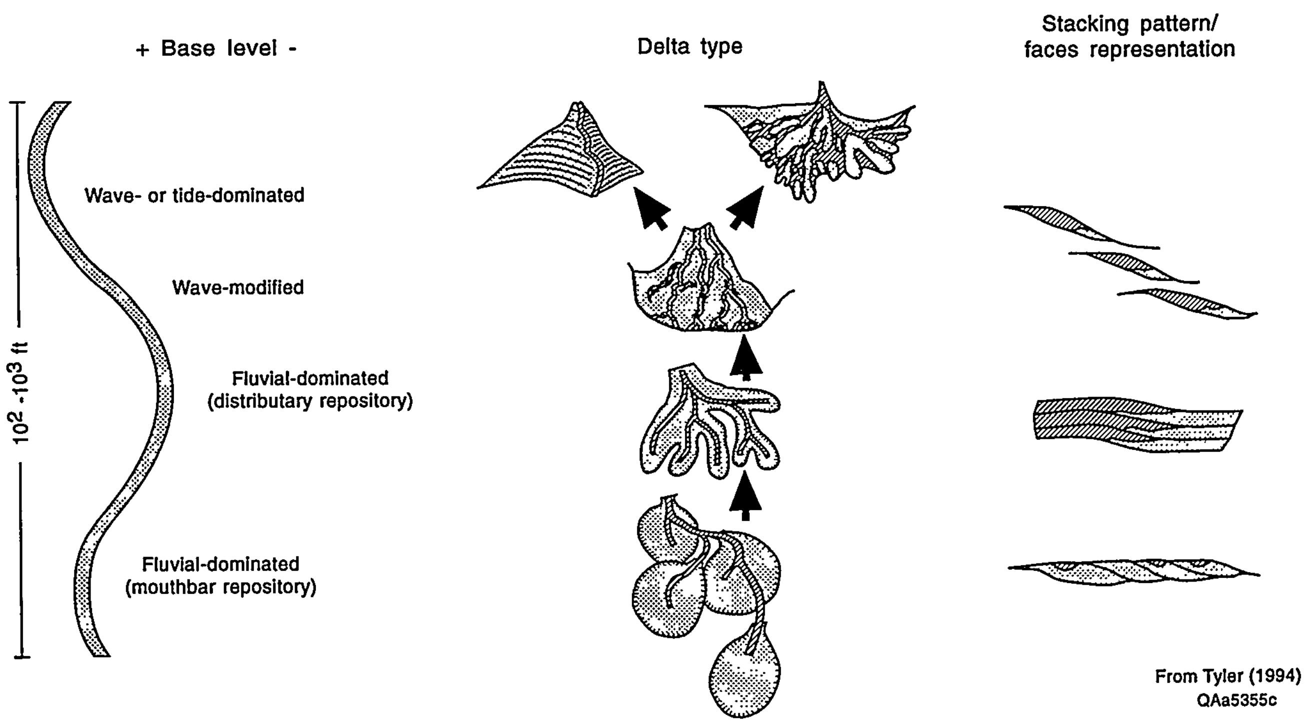


Figure 72. Influence of position within a depositional cycle on delta style and reservoir architecture. Because critical factors such as sediment supply, discharge, and shelf profile change through a depositional cycle, some change in delta morphology and facies can be expected. Periods of falling sea level may be marked by voluminous sandy sediment input because of devegetation of the source area, and may exhibit a broad shelf formed as the previous deltaic platform is exposed, resulting in an amplification of fluvial dominance. Conversely, during highstand, sediment input might be reduced (depending on climate effects in the source area) and wave energy might be dispersed by a broad, shallow shelf, increasing tidal influence on facies distribution. Modified from Tyler (1994).

mobility is a function of reservoir fluid viscosity and reservoir permeability, in which the relationship can be expressed as

$$\text{Mobility} = f(m, \log(k)) \qquad (1)$$

in which m is the average viscosity of the reservoir fluid (in cp) and k represents geometric mean permeability in md. (Average permeability can be substituted, as long as that substitution is made for all reservoirs being compared.) Because the average viscosity of reservoir fluid is not typically readily available, it can be approximated by weighted averaging of separate gas and oil phases in the reservoir using the following:

$$m = f(f(12, API)(100 - G) + 0.02^{*}G, 100) \qquad (2)$$

where API is the average gravity of the oil leg and G is the volume percent of the reservoir containing gas. The expression 12/API yields oil viscosity in cp on the basis of a cross plot of oil gravity versus viscosity for the Frio play and 0.02 is a mean value for gas viscosity (in cp) from the Frio play.

Reservoir depth is included as a criterion in order to compare economic viability of infill drilling that would occur during recovery of any identified resources. For a given volume of expected reserves at an infill location, shallower wells are more economic than deeper wells because of lower drilling costs. For example, a 10,000-bbl opportunity would be an economic target at a depth of 2,000 ft but would be clearly uneconomic at 8,000 ft.

Operator gas/oil preference is included in a quick-look evaluation because a given operator at a given time may be seeking to expand gas production more than oil production, or vice versa. This preference may occur because of commodity prices, infrastructure constraints, or contracted delivery goals.

The Formula

An equation has been established that incorporates readily available data from the above factors into a quantitative ranking of reservoirs in terms of their reserve growth potential. Because this formula is intended to yield a quick estimation of potential, it has several limitations, which are enumerated in the following section. The formula is as follows, with higher rank being equated to higher potential for economically recoverable reserves:

$$\text{RANK} = f(C\ (SUH)\ (SAH)\ V\ M\ G',\ D) \tag{3}$$

Where
C = current well spacing (acres)
SUH = structural heterogeneity, from 1 (low) through 10 (high)
SAH = stratigraphic heterogeneity, from 1 (low) through 10 (high)
V = relative volumetric importance, ranked from 1 (smallest) to 100 (largest)
M = mobility, represented by f(m,log(k))
G' = Gas/oil bias (gas preference, G' = G (% gas in reservoir), oil preference, G' = 100-G)
D = f(Depth, 6000) (economic risk factor - higher drilling costs for deeper reservoirs)
and
k = geometric mean or estimated average permeability in md.
m = average viscosity of reservoir fluid, given by:

f((f(12,API*)(100 - G) + 0.02**G),100), where API = reservoir oil gravity in API units.

* f(12,API) yields the viscosity of the oil in cp.
** 0.02 = viscosity of typical gas in cp.

Limitations

The quick-look prioritization equation is designed such that it utilizes input that should be readily available to an operator for almost all reservoirs. The intent is that such an evaluation should not require significant additional research or data gathering. In establishing such a relationship, many assumptions have been made. The influence of drive mechanism on recovery has been neglected, as has the variable efficacy of past reservoir management practices. Additionally, sandstones that have not been produced in the past, but that may contain future potential, are not considered.

Drive mechanism is known to affect recovery efficiency (API, 1967; Tyler and others, 1984). However, these effects are difficult to quantify and can change throughout the life of the reservoir depending on initial gas saturation and reservoir management practices. In decreasing order of efficiency, common drive mechanisms are (1) water drive, (2) gas cap expansion, and (3) solution gas drive. However, recovery from solution gas drive reservoirs can be altered during their life by gas injection programs which approximate gas expansion drives with variable success.

Another assumption inherent in the equation is that all reservoirs have experienced a similar degree of development and reservoir management. Certainly, though, not all reservoirs have been given the same level of attention by past operators in terms of looking for recompletion/infill opportunities or identifying production anomalies that would indicate compartmentalization. In addition, past mismanagement of water or gas injection programs can affect reserve growth potential, and this history can be difficult to discern in a quick-look evaluation. For instance, injection of water into downdip wells that are in direct communication with updip wells through narrow high permeability channel facies can result in large volumes of unswept oil in lateral facies between the channels.

Another possibility that is not considered in the quick-look evaluation is the potential for reserve growth in sandstones that have not previously been economically produced. Possible scenarios include (1) unrecognized low-resistivity pay zones, caused either by anomalous mineralogy or thinly bedded nature, (2) zones that have exhibited flow rates that were lower than desired during more prolific periods of field development, and (3) zones that have been misdiagnosed as unproductive because of unrecognized formation damage or unrecognized potential to produce when stimulated. Each of these situations would not be recognized by the above quick-look evaluation because of the lack of high relative reservoir volume (they are not considered reservoirs or have a low cumulative production volume).

TECHNOLOGY TRANSFER ACTIVITIES

P. R. Knox and W. G. White

The methodologies for advanced multidisciplinary reservoir characterization that have been developed and demonstrated in the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) play of South Texas by the Bureau of Economic Geology, The University of Texas at Austin, exhibit tremendous potential to increase near-term production in fluvial-deltaic reservoirs throughout the play, and are broadly applicable to fluvial-deltaic resources across the United States. To achieve this objective, however, operators must be made aware of these methodologies and their proven worth. The Bureau has expended substantial effort to transfer these technologies to domestic fluvial-deltaic operators, and particularly operators of Gulf Coast fluvial-deltaic reservoirs.

Through the course of this study, eleven presentations have been made at regional or national meetings of geological, geophysical, and engineering professional societies (Appendix 1). Results have been widely distributed in 15 publications, including articles, abstracts, and major contract reports (Appendix 2). Three short courses focused on study results, and results played a pivotal role in a fourth short course prepared for a project that had provided matching funds to this study (Appendix 3). The methodology and results have also been captured in an interactive software package titled the Reservoir Characterization Advisor—Fluvial-Deltaic, which could form the basis for future similar software demonstrating characteristics of reservoirs deposited in other settings such as carbonate platforms or slope and basin settings.

Presentations

Oral and poster presentations of project methods and results at regional and national technical conferences are one way to quickly transfer information, as soon as it becomes available, in a face-to-face format, to operators of fluvial-deltaic operators. Bureau scientists have provided 11 such presentations over the project life. In addition, two presentations to DOE-sponsored gatherings made other researchers aware of Bureau approaches and progress. On two occasions, a prominent operator within the Frio play invited Bureau scientists to present methods and results to reservoir teams working in this trend. Additionally, presentations have been made to the operators of fields studied in detail to communicate specific opportunities for reserve growth identified by the Bureau. Other oral presentations given at short courses are covered under that section heading.

Audiences at presentations to technical societies have ranged from 25 senior independent oil and gas operators at a regional meeting to hundreds of geoscientists at a national meeting. All presentations received positive audience response and several have resulted in invitations to make follow-up presentations to individual operators. The eleven oral or poster presentations are listed in Appendix 1 and include:

- 1 poster presentation, joint national meeting of the American Association of Petroleum Geologists (AAPG) and SEPM (Society for Sedimentary Geology), April 1994, Denver, Colorado
- 1 oral presentation, Gulf Coast Association of Geological Societies (GCAGS), October 1994, Austin, Texas
- 2 oral and 1 poster presentation, national AAPG-SEPM, March 1995, Houston, Texas
- 2 oral presentations, GCAGS, October 1995, Baton Rouge, Louisiana
- 1 oral presentation, Society of Petroleum Engineers/DOE Improved Oil Recovery Conference, April 1996, Tulsa, Oklahoma
- 1 oral presentation, national AAPG-SEPM, May 1996, San Diego, California
- 1 oral presentation, GCAGS, October 1996, San Antonio, Texas
- 1 oral presentation, Society for Independent Professional Earth Scientists monthly meeting, May 1996, San Antonio, Texas

Bureau researchers have also been invited to present interim findings at Contractors Meetings convened by DOE. Presentations at Fountainhead, Oklahoma, in 1993 and 1995 reported interim results to the DOE and allowed for cross-fertilization among the Class I projects.

Presentations by Bureau staff at the national AAPG-SEPM meeting held in Houston precipitated two invitations from a Pennzoil team working in the Frio play. The operator covered expenses for two day-long visits to the Houston headquarters to present methods and findings from this study. The presentations were well received and the visits allowed for working discussions on specific issues being faced by the operator.

Finally, specific opportunities for reserve growth in the two fields selected for detailed study will be presented to the operators involved. A presentation was made to the Mobil T-C-B reservoir team in early 1995 to present interim findings. Final meetings with Mobil and Conoco (Rincon field) will be held in August 1996 to present final results.

Publications

In addition to presentations, methods and results have been published in several forms to provide a more permanent and widely circulated documentation of ways to increase near-term production from mature fluvial-deltaic reservoirs. Articles in transaction volumes for meetings where presentations have been made provide details and figures so that attendees and those unable to attend can fully comprehend the more complicated aspects of characterization. Abstracts in convention volumes can entice operators to presentations and provide summaries for those unable to attend. In-depth information on project details and results has been presented in annual and topical project reports to the DOE, and project results have been highlighted in the DOE Fall, 1996 edition of the DOE publication "The Class Act."

Appendix 2 lists all publications produced by this project. These include three articles in the Transactions volumes from the 1994 and 1995 GCAGS meetings and one article in the Transactions of the SPE/DOE Improved Oil Recovery Conference, 1996. A total of six abstracts have been published in convention volumes accompanying the 1994, 1995, and 1996 national AAPG-SEPM meetings and the 1996 GCAGS meeting. Project reports to the DOE have included three annual reports, two topical reports (one focused on regional play evaluation and one on detailed reservoir characterization), and this final report. A two-page article in the fall, 1996 "Class Act" newsletter that is circulated to operators of fluvial-deltaic reservoirs is anticipated to yield requests for additional copies of project reports, possibly leading to the increased application of advanced characterization methodology and resulting increases in production from fluvial-deltaic reservoirs.

Short Courses

Short courses and workshops provide an opportunity to meet and train operators who are interested in applying integrated characterization methods to their reservoirs. It is a forum for providing detailed information and conducting question and answer sessions. This ensures a deeper understanding of the steps required in identifying remaining resources and increases the confidence of operators in applying these steps, thereby improving the likelihood of increasing near-term production. Original project goals included two short courses, to be held in cities convenient to operators in the Frio play. During the project opportunities arose for an additional one-half day course and participation in a three-day field workshop. Attendees to each of these courses were provided course notebooks containing figures and text for future reference and annotation. Topics presented at each of the workshops are given in Appendix 3 in the form of course schedules.

Planned One-Day Courses

Two one-day short courses were held in the Spring of 1996 in San Antonio and Houston in order to be convenient for operators of Gulf Coast fluvial-deltaic reservoirs. The purpose was to present (1) an overview of Frio play characteristics, (2) details of the integrated multidisciplinary reservoir characterization methodology, (3) examples of its application within the Frio play, (4) strategies for identifying reservoirs prospective for detailed characterization studies, and (5) an overview of the Reservoir Characterization Advisor—Fluvial-Deltaic (RCA—FD) software. In addition, core material from Frio fluvial-deltaic reservoirs in Rincon field was available for viewing and discussion and the RCA—FD was demonstrated during breaks.

The first course was held in San Antonio, Texas, on Monday, April 8, 1996, at the Bright Shawl restaurant and meeting complex, and was hosted by the South Texas Geological Society.

The minimal registration cost of $45 included lunch and a 3-inch-thick 3-ring binder course notebook. The notebook contained annotated handouts of slides, a bibliography of publications and articles pertinent to fluvial-deltaic reservoir characterization, copies of the latest project annual report and a Bureau publication of playwide resource assessment, and several pamphlets on seismic and well log interpretation published jointly by Gas Research Institute (GRI), DOE, and the Bureau. The course was attended by 25 operator representatives from the San Antonio area. Audience feedback was positive, with the RCA—FD software demonstration receiving high levels of interest. Special presenters included Dr. George Asquith of Texas Tech University lecturing on the interpretation of old e-logs and Dr. Bob Hardage discussing how to design a 3-D seismic survey.

The second course was held in Houston on June 6, 1996, at the Exxon Auditorium, and was hosted by the Houston Geological Society. Again, the minimal cost of $50 (at-the-door and non-member fee higher) included a complete course notebook. Paid attendance was 75. As before, cores and a RCA—FD demonstration were available at breaks and Dr. Bob Hardage served as a special presenter. Responses to a questionnaire passed out at the end of the meeting provided substantial encouragement that many operators intended to apply the methodology in mature Gulf Coast reservoirs. Nearly all of the questionnaire respondents were geologists, engineers, or geophysicists working for independent oil companies or consulting firms, with responsibilities for reservoirs on the Texas Gulf Coast. Evaluations of course content were overwhelmingly positive, with some opposing opinions regarding the ratio of time spent on methodology versus examples. The presentation of how to do 3-D geocellular modeling received all positive comments, as did the overall reservoir characterization methodology.

PTTC/TIPRO Workshop

The beneficial collaboration of the Bureau with the Texas Independent Producers and Royalty Owners Association (TIPRO) and the Petroleum Technology Transfer Council (PTTC) created an additional opportunity to meet with operators and present a methodology for integrated reservoir characterization. A significant portion of the meeting was a discussion period in which operators expressed their opinions on factors that inhibited increased production in fluvial-deltaic reservoirs.

A total of 29 operators, geologists, engineers, and geophysicists attended the August 1995 one-half day meeting in Houston. The presentation portion of the meeting was divided into three sections. The first part was an introduction to Texas oil and gas plays and reserve growth concepts while the second and third portions discussed Frio playwide characteristics and reservoir characterization methodology, respectively. It was emphasized to the operators and independent geologists present that the great bulk of reserve growth in this play will come within already discovered reservoirs.

Questions and concerns raised by the audience during the question and answer session included the applicability of 3-D seismic in the Frio play and the cost and difficulty of obtaining production and log information from these mature fields. It was emphasized that 3-D seismic is very applicable to characterization of fluvial-deltaic reservoirs but that operators must be aware of the difference in vertical resolution between well logs and seismic data. Additionally, it was relayed that the Railroad Commission of Texas is working on computerizing production files to simplify access and that logs in the archives of the Bureau are available to operators for only the cost of reproduction.

GRI Ferron Field Trip

Results of this study were also presented to 22 geoscientists from major and large independent oil companies during a three-day field trip intended to demonstrate controls on reservoir architecture and heterogeneity at the between-well scale. This trip to see exposures of the Ferron Sandstone in central Utah was an outgrowth of an Industrial Associates (IA) program being conducted at the Bureau. This IA program has provided matching funding to the Frio study and established many relationships from the outcrop that the Frio study has then applied in the subsurface.

The evening before the first field day, participants were given an overview of observations from the Ferron study, including data indicating that reservoir architecture and heterogeneity vary in a given facies throughout a depositional cycle. The concluding presentation documented the application and testing of this concept in the subsurface study of Frio reservoirs. Specifically, it documented that, as predicted by outcrop observations, fluvial upper delta plain channels deposited during progradational or aggradational portions of a depositional cycle (e.g., upper Whitehill reservoir of T-C-B field) were less internally heterogeneous than those deposited during the retrogradational portion of a depositional cycle (e.g., upper Scott reservoir of T-C-B field). This heterogeneity controls reservoir drainage efficiency and dictates optimum well spacing in subsurface reservoirs. Thus, the talk underscored the practical utility of the outcrop studies and was well received.

Reservoir Characterization Advisor Software

Introduction

In an effort to make the results of this study available to operators on a day-to-day basis, and in a form that is most useful and flexible, we have incorporated methods and results into a microcomputer-based software package referred to as the Reservoir Characterization Advisor—Fluvial Deltaic (RCA—FD). While the basic reservoir characterization methodology is applicable to nearly all reservoirs, specific information for the fluvial deltaic setting and examples from fluvial-deltaic reservoirs have been provided. The RCA—FD has been designed in a modular format so that future versions covering other depositional settings can easily be constructed. The RCA—FD is also designed to be user-friendly and compatible with nearly any computer in use by operators within the Frio Fluvial-Deltaic Sandstone Play.

The RCA—FD will combine text and illustrations with simple calculation functions. In this way it will provide an illustrated guide to carrying out reservoir characterization studies, as well as enable operators to calculate parameters specific to their reservoirs. The various features available in this software will produce a powerful tool that will improve the efficiency and productivity of operators of mature fluvial/deltaic reservoirs, resulting in more characterization studies undertaken and more recompletion and infill-drilling activity. Ultimately, it will lead to reserve growth and increased production and prevent the premature abandonment of mature reservoirs.

Software Development

The RCA—FD demonstrates the planning process and strategies employed in the real world when characterizing reservoirs to identify reserve growth potential and is based on actual Bureau research strategies developed over the last 15 years. The intended user audience is the independent oil exploration company, which may not have the in-house expertise available to larger companies.

The RCA—FD uses a multimedia approach, incorporating text, graphics, application tools such as spreadsheets, and animation to guide the user through the process of ranking reservoirs in terms of reserve growth, followed by the four basic steps of detailed reservoir characterization used to identify specific reserve growth opportunities. The four steps of reservoir characterization are presented as separate modules in the advisor, which build cumulatively: (1) determining reservoir architecture, (2) establishing fluid-flow trends, (3) integrating architecture and fluid-flow, and (4) combining the results of previous steps to quantify the reserve growth potential of the reservoir and delineate recompletion and infill-drilling opportunities.

The RCA—FD is written for the PC-compatible platform and requires at least a 386 CPU running Windows, and an SVGA monitor to display the graphics and animation. RCA—FD is written in Microsoft Visual Basic 4.0, which employs many user-friendly application controls to assist the user in running the software: menus, hypertext links, clickable buttons, dialog boxes, and online help. An online, searchable glossary of reservoir characterization terms will be a component of the package; the user can either call up the glossary directly and look up definitions, or click on highlighted terms which appear throughout the body of the RCA—FD text screens.

Graphics are an important component of the package as well: graphs, charts, and well log images will be displayed appropriately to illustrate and underscore points presented in the text. Simple animations will be employed to effectively communicate time-dependent processes.

The RCA—FD serves as a complete tutorial package, allowing users to work at their own pace. Users may choose to stop at any point and come back later to the same point in the tutorial or to review material already presented. Basic analysis procedures are presented so that the user can grasp the general idea. These procedures are first shown to the user with sample data developed by Bureau content experts, then, in some modules, the user can enter their data for analysis, such as in the quick-look reservoir prioritization module. When the user is prompted to enter real-world data to work through certain procedures, that data will be stored as a workbook for recall and use in later procedures as appropriate. The workbook can then be printed at the completion of the tutorial for a permanent record of the user's work.

Distribution

Each of the RCA—FD CD will be distributed on several floppy discs, accompanied by a brief publication that provides an overview of its contents and use. These items will be packaged in a 3-ring binder and priced at a cost sufficient to cover reproduction of the materials.

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APPENDIX 1: List of Presentations Produced by BEG Class I Project.

1993

Dutton, S. P., Revitalizing a mature oil play: strategies for finding and producing unrecovered oil in Frio fluvial-deltaic reservoirs of South Texas: presented at the Department of Energy Oil Program Contractor Review Meeting in Fountainhead, Oklahoma, July 1993.

1994

McRae, L. E., and Holtz, M. H., Targeting the unrecovered oil resource in mature field areas: an example from Oligocene Frio fluvial-deltaic reservoirs of South Texas, Rincon field, South Texas: AAPG Annual convention, May, Denver, Colorado (poster).

McRae, L. E., and Holtz, M. H., Integrated reservoir characterization of mature oil reservoirs: an example from Oligocene Frio fluvial-deltaic sandstones, Rincon field, South Texas: Gulf Coast Association of Geological Societies, October, Austin, Texas.

1995

Holtz, M. H., and McRae, L. E., Modeling reservoir attributes and estimating additional hydrocarbon potential for redevelopment in fluvial-deltaic reservoirs: An example from the Frio fluvial-sandstone play in South Texas: AAPG Annual convention, April, Houston, Texas (poster).

Knox, P. R., and McRae, L. E., High-resolution sequence stratigraphy: the key to identifying compartment styles in Frio Formation fluvial-deltaic reservoirs, T-C-B Field, South Texas: AAPG Annual convention, April, Houston, Texas.

McRae, L. E., and Holtz, M. H., Reservoir architecture and permeability characteristics of fluvial-deltaic sandstone reservoirs in the Frio Formation, Rincon field, South Texas: AAPG Annual convention, April, Houston, Texas.

Holtz, M. H., Characterization of Frio fluvial-deltaic reservoirs, South Texas: U. S. Department of Energy Contractors meeting, Fountainhead, Oklahoma, June 1995.

Knox, P. R., Predicting reservoir architecture and internal heterogeneity in upper delta plain settings: Implications for reserve-growth potential and development strategies, presented to Pennzoil Exploration and Production Company, June, Houston, Texas.

Dutton, S. P., Revitalizing a mature oil play: strategies for finding and producing unrecovered oil in Frio fluvial-deltaic reservoirs of South Texas: presented at the Department of Energy Oil Program Contractor Review Meeting in Fountainhead, Oklahoma, July 1993.

Knox, P. R., and McRae, L. E., Application of sequence stratigraphy to the prioritization of incremental growth opportunities in mature fields: an example from Frio fluvial-deltaic sandstones, TCB field, South Texas: Gulf Coast Association of Geological Societies, October, Baton Rouge, Louisiana.

McRae, L. E., and Holtz, M. H., Strategies for optimizing incremental recovery from mature reservoirs in Oligocene Frio fluvial-deltaic sandstones, Rincon field, South Texas: Gulf Coast Association of Geological Societies, October, Baton Rouge, Louisiana.

Knox, P. R., Progress Report: T-C-B field reservoir characterization, presented to Mobil Exploration and Producing U.S., Inc., Houston, Texas.

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Holtz, M. H., and Hamilton, D. S., Reservoir characterization methodology to identify reserve growth potential: SPE/DOE Improved Oil Recovery Conference, April, Tulsa, Oklahoma.

Knox, P. R. , Accommodation-based controls on fluvial-deltaic reservoir compartmentalization: Examples from the Oligocene Frio Formation, South Texas: AAPG Annual convention, May, San Diego, California.

Knox, P. R., Predicting between-well reservoir architecture and heterogeneity in fluvial-deltaic sandstones on the basis of position within a depositional cycle: Society of Independent Professional Earth Scientists, May, San Antonio, Texas.

Knox, P. R., Determining Between-Well Reservoir Architecture in Deltaic Sandstones Using Only Well Data: Oligocene Frio Formation, Tijerina-Canales-Blucher Field, South Texas: Gulf Coast Association of Geological Societies, October, San Antonio, Texas.

APPENDIX 2: List of Publications Produced by BEG Class I Project.

1994

Holtz, M. H., McRae, L. E., and Tyler, Noel, 1994, Identification of remaining oil resource potential in the Frio fluvial-deltaic sandstone play, South Texas: The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the U.S. Department of Energy, Bartlesville Project Office, under contract no. DE-FC22-93BC14959, report no. DOE/BC/14959-8 (DE94000132), 67 p.

McRae, L. E., and Holtz, M. H., 1994, Integrated reservoir characterization of mature oil reservoirs: an example from Oligocene Frio fluvial-deltaic sandstones, Rincon field, South Texas: Gulf Coast Association of Geological Societies Transactions, v. 44, p. 487–498.

McRae, L. E., and Holtz, M. H., 1994, Targeting the unrecovered oil resource in mature field areas: an example from Oligocene Frio fluvial-deltaic reservoirs of South Texas, Rincon field, South Texas (abs.) *in* AAPG Annual convention official program: analogs for the world: Denver, American Association of Petroleum Geologists, p. 213.

McRae, L. E., Holtz, M. H., and Knox, P. R., 1994, Revitalizing a mature oil play: strategies for finding and producing unrecovered oil in Frio fluvial-deltaic reservoirs of South Texas: The University of Texas at Austin, Bureau of Economic Geology, annual report prepared for the U.S. Department of Energy, Bartlesville Project Office, under contract no. DE-FC22-93BC14959, report no. DOE/BC/14959-5 (DE94000131), 93 p.

1995

Holtz, M. H., and McRae, L. E., 1995, Identification and assessment of remaining oil resources in the Frio fluvial-deltaic sandstone play, South Texas: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 227, 46 p.

Holtz, M. H., and McRae, L. E., 1995, Modeling reservoir attributes and estimating additional hydrocarbon potential for redevelopment in fluvial-deltaic reservoirs: An example from the Frio fluvial-sandstone play in South Texas (abs.), *in* AAPG Annual convention official program: Houston, American Association of Petroleum Geologists, v. 4, p. 42A–43A.

Knox, P. R., and McRae, L. E., 1995, Application of sequence stratigraphy to the prioritization of incremental growth opportunities in mature fields: an example from Frio fluvial-deltaic sandstones, TCB field, South Texas: Gulf Coast Association of Geological Societies Transactions, v. 45, p. 341–359.

Knox, P. R., and McRae, L. E., 1995, High-resolution sequence stratigraphy: the key to identifying compartment styles in Frio Formation fluvial-deltaic reservoirs, T-C-B Field, South Texas (abs.), *in* AAPG Annual convention official program: Houston, American Association of Petroleum Geologists, v. 4, p. 51A.

McRae, L. E., and Holtz, M. H., 1995, Reservoir architecture and permeability characteristics of fluvial-deltaic sandstone reservoirs in the Frio Formation, Rincon field, South Texas (abs.), *in* AAPG Annual convention official program: Houston, American Association of Petroleum Geologists, v. 4, p. 64A.

McRae, L. E., and Holtz, M. H., 1995, Strategies for optimizing incremental recovery from mature reservoirs in Oligocene Frio fluvial-deltaic sandstones, Rincon field, South Texas: Gulf Coast Association of Geological Societies Transactions, v. 45, p. 423–434.

McRae, L. E., Holtz, M., Hentz, T., Chang, C., and Knox, P. R., 1995, Strategies for reservoir characterization and identification of incremental recovery opportunities in mature reservoirs in Frio fluvial-deltaic sandstones, South Texas: an example from Rincon field, Starr County: The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the U.S. Department of Energy, Bartlesville Project Office, under contract no. DE-FC22-93BC14959, report no. DOE/BC/14959-15 (DE95000190), 111 p.

McRae, L. E., Holtz, M. H., and Knox, P. R., 1995, Revitalizing a mature oil play: strategies for finding and producing unrecovered oil in Frio fluvial-deltaic reservoirs of South Texas: The University of Texas at Austin, Bureau of Economic Geology, annual report prepared for the U.S. Department of Energy, Bartlesville Project Office, under contract no. DE-FC22-93BC14959, report no. DOE/BC/14959-13 (DE95000160), 155 p.

1996

Holtz, M., McRae, L. E., Knox, P. R., Hentz, T., and Chang, C., 1996, Revitalizing a mature oil play: strategies for finding and producing unrecovered oil in Frio fluvial-deltaic reservoirs of South Texas: The University of Texas at Austin, Bureau of Economic Geology, annual report prepared for the U.S. Department of Energy, Bartlesville Project Office, under contract no. DE-FC22-93BC14959, report no. DOE/BC/14959-17 (DE96001211), 178 p.

Holtz, M. H., and Hamilton, D. S., 1996, Reservoir characterization methodology to identify reserve growth potential: SPE Paper 35434, 12 p.

Knox, P. R. , 1996, Accommodation-based controls on fluvial-deltaic reservoir compartmentalization: Examples from the Oligocene Frio Formation, South Texas (abs.), *in* AAPG Annual convention official program: San Diego, American Association of Petroleum Geologists, v. 5, p. A76.

Knox, P. R., 1996, Determining Between-Well Reservoir Architecture in Deltaic Sandstones Using Only Well Data: Oligocene Frio Formation, Tijerina-Canales-Blucher Field, South Texas (abs.): Gulf Coast Association of Geological Societies Transactions, in press.

Knox, P. R., 1996, Integrated Characterization Yields Targeted Infill/Recompletion Opportunities: The Class Act, U.S. DOE Bartlesville Project Office, in press, 2 p.

APPENDIX 3: Content of Short Courses Produced by BEG Class I Project.

New Oil From Old Fields: Identifying Opportunities for Reserve-Growth Potential in Mature Fields of the Frio Fluvial/Deltaic Sandstone Play, Vicksburg Fault Zone

Short Course Schedule

9:00 -9:15	Welcome and Workshop Overview
9:15 - 9:45	Frio Fluvial/Deltaic Play Characteristics
9:45 - 10:00	Integrated Reservoir Characterization Methodology: Overview
10:00 - 10:15	The Geologic Advisor
10:15 - 10:30	*Break*
10:30 - 11:00	Sequence Stratigraphic Concepts, Introduction to Facies Identification in Deltaic Systems
11:00 - 12:00	Geological Identification of Reservoir Architecture
12:00 - 1:00	*Lunch*
1:00 - 1:45	The Interpretation of Old E-Logs
1:45 - 2:00	Frio Fluvial/Deltaic Petrophysical Characteristics
2:00 - 2:30	The Power and Benefits of 3-D Seismic
2:30 - 3:05	Geophysical Identification of Reservoir Architecture
3:05 - 3:20	*Break*
3:20 - 4:05	Developing the Reservoir Model–Integrating Geology, Geophysics, and Engineering
4:05 - 4:20	Identifying Reserve Growth Potential
4:20	Concluding Remarks

Hosted by the South Texas Geological Society
San Antonio, Texas, April 8, 1996

APPENDIX 3: Content of Short Courses associated with BEG Class I Project.

New Oil From Old Fields: Identifying Opportunities for Reserve–Growth Potential in Mature Fields of the Frio Fluvial/Deltaic Sandstone Play, Vicksburg Fault Zone

Short Course Schedule

8:00 – 8:10	Welcome and Workshop Overview *(Major)*
8:10 – 8:40	Frio Fluvial/Deltaic Play Characteristics *(Holtz)*
8:40 – 9:40	Sequence Stratigraphic Concepts, Introduction to Facies Identification in Deltaic Systems *(Knox)*
9:40 – 10:10	Integrated Reservoir Characterization Methodology: Overview *(Holtz)*
10:10 – 10:30	The Geologic Advisor *(White)*
10:30 – 10:45	*Break*
10:45 – 11:45	Geological Identification of Reservoir Architecture *(Knox)*
11:45 – 1:00	*Lunch*
1:00 – 2:00	Power and Benefits of 3-D Seismic *(Hardage)*
2:00 – 2:30	Geophysical Identification of Reservoir Architecture *(Paine)*
2:30 – 3:00	Frio Fluvial/Deltaic Petrophysical Characteristics *(Holtz)*
3:00 – 3:15	*Break*
3:15 – 4:15	Developing the Reservoir Model–Integrating Geology, Geophysics, and Engineering *(Holtz)*
4:15 – 4:45	Reservoir Prioritization *(Knox, Holtz)*
4:45	Concluding Remarks and Questionnaire *(Major)*

Hosted by the Houston Geological Society
Houston, Texas, June 6, 1996

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