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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

Annual Report for the Period
October 1993 to October 1994

By
L. E. McRae, M. H. Holtz, and P. R. Knox

July 1995

Performed Under Contract No. DE-FC22-93BC14959

The University of Texas at Austin
Austin, Texas

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INTRODUCTION

Fluvial-deltaic sandstone reservoirs represent significant opportunities for re-development in mature fields throughout the world. They presently account for more than 34 billion barrels of unrecovered oil resources in the United States and, as a class, represent the highest percentage of remaining mobile oil resources in clastic reservoirs throughout the state of Texas (Figure 1). The stratigraphic complexity inherent in these deposits is responsible for low recovery efficiencies in large part because of the isolation of significant volumes of mobile oil in undeveloped reservoir compartments (Figure 2). These unproduced zones can be identified by integrated geological and engineering reservoir characterization and targeted for incremental recovery by recompletions and infill drilling.

The Frio Fluvial-Deltaic Sandstone Play of South Texas is one example of a mature play where reservoirs are being abandoned at high rates, potentially leaving behind significant unrecovered resources in untapped and incompletely drained reservoirs. Nearly 1 billion barrels of oil have been produced from Frio reservoirs since the 1940's, yet more than 1.6 BSTB of unrecovered mobile oil is estimated to remain in the play. Frio reservoirs of the South Texas Gulf Coast are being studied to better characterize interwell stratigraphic heterogeneity in fluvial-deltaic depositional systems and determine controls on locations and volumes of unrecovered oil. Engineering data from fields throughout the play trend were evaluated to characterize variability exhibited by these heterogeneous reservoirs and were used as the basis for resource calculations to demonstrate a large additional oil potential remaining within the play.

Study areas within two separate fields have been selected in which to apply advanced reservoir characterization techniques. Stratigraphic log correlations, reservoir mapping, core analyses, and evaluation of production data from each field study area have been used to characterize reservoir variability present within a single field. Differences in sandstone depositional styles and production behavior were assessed to identify zones with significant stratigraphic heterogeneity and a high potential for containing unproduced oil. Detailed studies of selected reservoir zones within these two fields are currently in progress. Development of reservoir flow-unit architecture, described by log

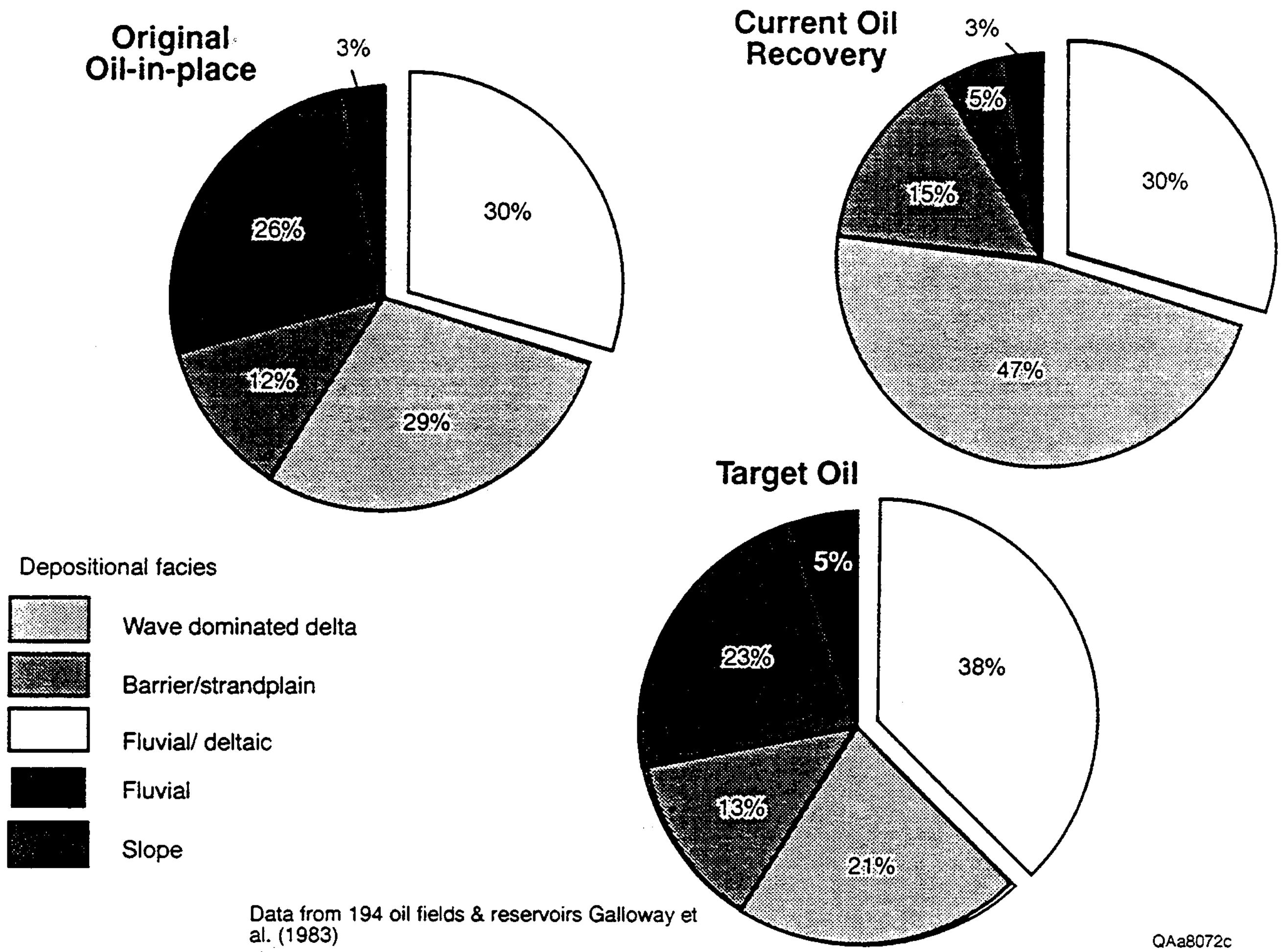

Figure 1. Pie diagrams illustrating the distribution of original-oil-in-place, cumulative oil produced, and current estimates of remaining mobile oil resources in Texas oil reservoirs representing various clastic depositional facies. Data from Galloway and others (1983) and Tyler and others (1984).

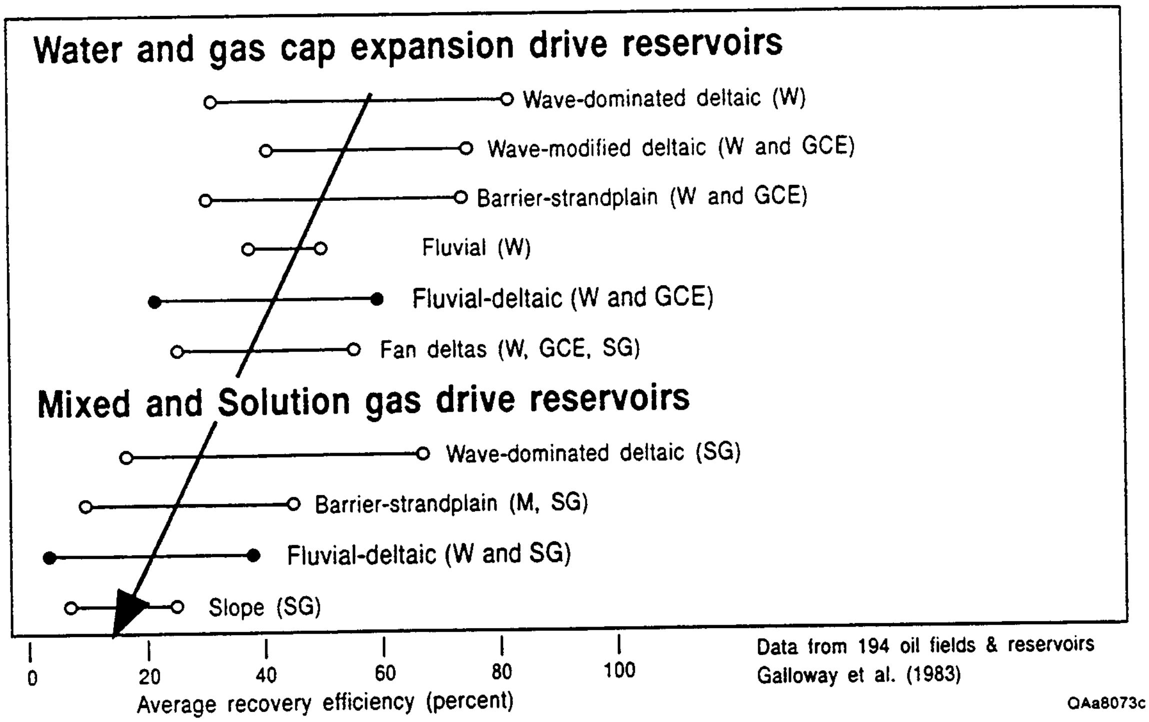

Figure 2. Range of recovery efficiencies reported for various clastic oil reservoirs in Texas. Adapted from Tyler and Finley (1991). Letters following depositional environment categories refer to type of reservoir drive mechanism: W, water, GCE, gas-cap expansion, SG, solution gas, and M, mixed.

facies and petrophysical core studies integrated with production data, will form the basis for the identification of potential locations of unproduced recoverable oil. The methodology demonstrated here has direct application to other reservoirs in these fields, other fields in the Frio Fluvial-Deltaic Sandstone Play in South Texas play, as well as fields outside the play representing analogous depositional settings.

PROJECT SUMMARY

Project Description

The Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) play of South Texas has produced nearly 1 Bbbl of oil equivalent from more than 129 reservoirs in fields throughout the play in South Texas since field development began in the late 1930's and early 1940's (Galloway and others, 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. In 1991, over one half of the 129 reservoirs included in the play were no longer producing, and the reservoirs still producing contributed only 0.1 percent of the cumulative production. Unless new strategies are developed to locate this unrecovered oil, this very significant resource will likely remain unproduced.

The objectives of this project are to develop interwell-scale geological facies models of Frio fluvial-deltaic reservoirs from selected fields in South Texas and combine them with engineering assessments to characterize reservoir architecture and flow-unit boundaries and to try to determine the controls that these characteristics exert on the location and volume of unrecovered mobile and residual oil. Results of these studies should lead directly to the identification of specific near-term opportunities to exploit these heterogeneous reservoirs for incremental recovery by recompletion and strategic infill drilling (Table 1).

Project Task Breakdown

The project is divided into three major phases (Figure 3). The first phase includes (1) the initial tasks 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

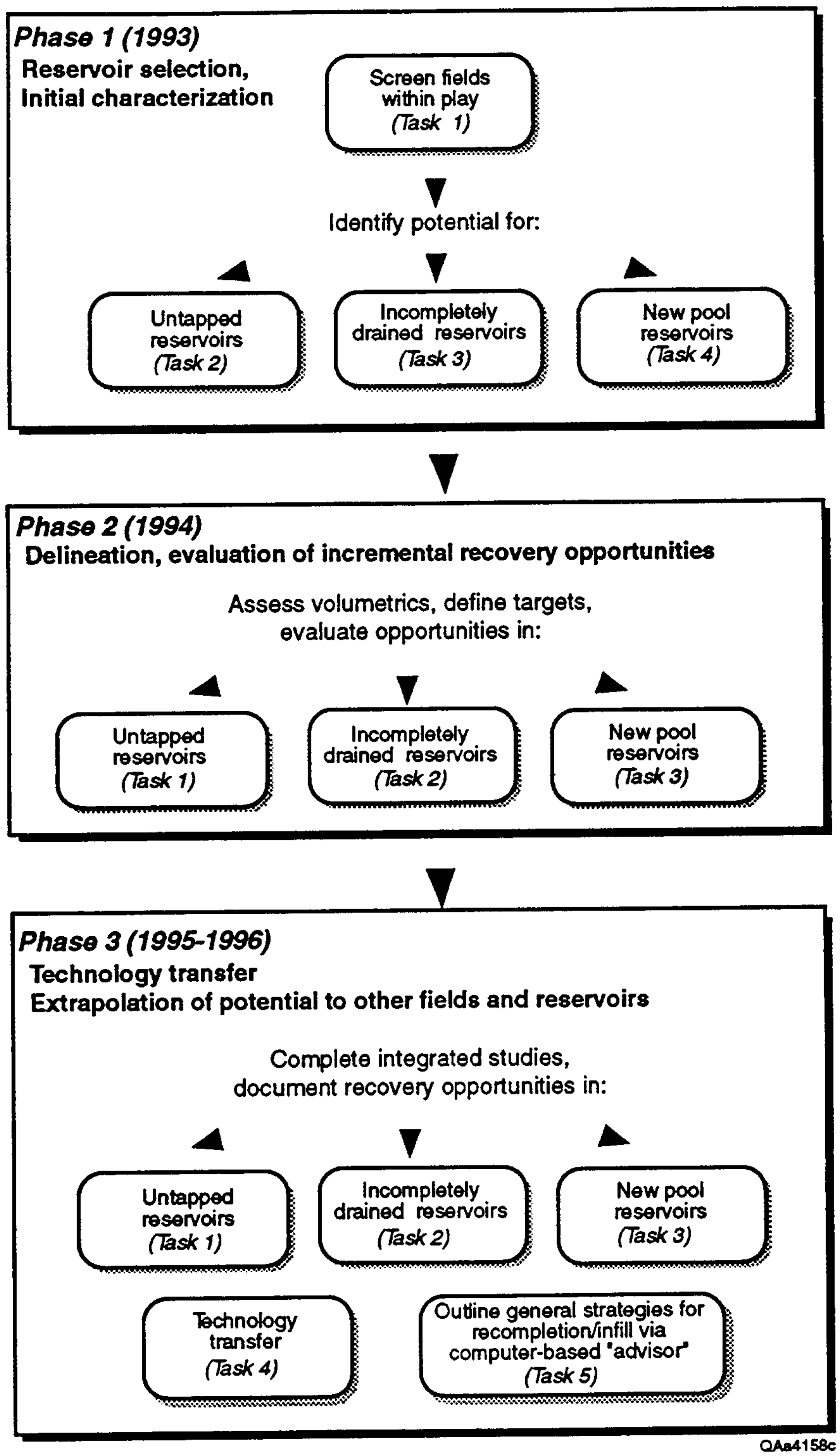

Figure 3. Diagram of work structure for this project illustrating three primary phases and a breakdown of individual tasks associated with each phase of the project. Phase II studies were carried out during the second project year and are the focus of this report.

characterization studies on these selected reservoirs in order to identify the potential for untapped, incompletely drained, and new pool reservoirs (tasks 2–4).

The second phase involves advanced characterization of the selected reservoirs in order to delineate incremental resource opportunities. Subtasks within Phase II include volumetric assessments of untapped and incompletely drained oil, along with an analysis, by reservoir, of specific targets for recompletion and strategic infill drilling. The third and final phase of the project will consist 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. This annual report documents technical work completed as part of project Phase II that took place during the second year of the contract award, from October 1993 through October 1994.

Table 1. Summary of project objectives.

OBJECTIVE	APPROACH
1. Demonstrate the application of state-of-the-art reservoir characterization to incremental recovery of additional oil in known fields	• 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	• Focus on depositional and diagenetic heterogeneity rather than structural complexity
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 opportunities for infield reserve additions in selected fields by identifying specific targets for strategic infill drilling and well recompletion	• 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

Summary of Year 1 Progress

During the first year of the contract award (October 1992-October 1993) playwide field screening and field selection (Phase I) were accomplished and initial reservoir characterization studies (Phase II) were begun. Complete documentation of work completed during the initial reporting period is documented in McRae and others (1994); a brief summary is included here for reference (Table 2).

Fields throughout the play were screened to identify reservoirs that have a large remaining oil resource, are in danger of premature abandonment, and have geological and production data in sufficient quantity and of suitable quality to facilitate advanced reservoir characterization studies. The approach that was used to assess the potential for incremental reserve growth in mature fields of the Frio Fluvial-Deltaic Sandstone play was based on the statistical characteristics of reservoir volumes. Reservoir data from throughout the Frio Fluvial-Deltaic Sandstone play were compiled in an effort to characterize reservoir parameters and generate resource estimates, and these formed the basis for assessing the additional uncontacted and incompletely drained potential in the play as a whole.

Table 2. 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 analyses data by reservoir

Two Texas fields were selected for detailed investigation: Tijerina-Canales-Blucher (T-C-B) field, located in the northern portion of the trend in Jim Wells County, and Rincon field, located to the south in Starr County. Operators from both fields provided base maps and access to existing completion records, reservoir production histories, and extensive well data files.

Reservoir evaluation during the first project year focused on developing a detailed stratigraphic framework of the productive reservoir interval and on evaluating engineering data from reservoirs in both field areas. Electric-log and core data were evaluated in order to map regional facies patterns and construct field-wide reservoir correlations to help identify interwell stratigraphic heterogeneity and the potential for compartmentalization of significant volumes of unrecovered hydrocarbons. Production data, including completion density, abandonment rates, and production trends for individual reservoirs, were evaluated in order to assess the level of remaining potential for each productive reservoir zone. Reservoir development histories for major oil producing zones in both fields were reconstructed in order to rank and prioritize zones with the best potential for incremental reserve growth.

The primary objective of initial Phase I reservoir studies was to identify general styles of interwell stratigraphic heterogeneity, complete a preliminary assessment of additional resource potential of individual reservoir units, and select individual reservoir zones with significant potential for incremental recovery for further analysis to delineate the locations and volumes of unrecovered mobile oil. On the basis of the results from this initial work, two reservoir zones from each field were identified to be the focus of detailed characterization studies during project Phase II.

OVERVIEW OF PROJECT YEAR 2

Phase II Objectives

The goal of Phase II is to delineate incremental recovery opportunities in the reservoirs that were chosen for detailed study during Phase I. Project work in Phase II has been divided into three tasks. The goal of Task 1 is advanced reservoir characterization of potentially untapped reservoir compartments, in which depositional and diagenetic heterogeneities are assessed in detail to define recompletion opportunities. Identification of untapped compartments begins with the delineation of reservoir compartment architecture. The methods being used include facies mapping using logs and cores, high-resolution sequence stratigraphic analysis, comparison of petrographic observations with petrophysical measurements of core, special core analysis (capillary pressure, formation resistivity, and core flood tests), and analysis of production data from each reservoir.

The purpose of Task 2 is the assessment of reservoir compartmentalization in incompletely drained reservoirs. Specific opportunities for strategic infill drilling and recompletion are being evaluated as reservoir characterization proceeds. The methods being used to assess reservoir compartmentalization include those listed under Task 1, and again, the first step in defining incompletely drained reservoirs is to better understand reservoir compartment style. The presence of separate compartments may be indicated if significant differences exist between hydrocarbon volumes calculated by reservoir size and volumes proven from present cumulative production and projected from decline-curve analysis.

The effort on Task 3, the evaluation of the potential for new pool reservoirs, is more limited in scope than that for tasks 1 and 2. As facies and other types of maps are constructed during tasks 1 and 2, new pool potential may be defined, but localization of this resource is secondary to the efforts of delineating untapped and incompletely drained potential.

The separate project subtasks associated with the delineation and evaluation of incremental recovery opportunities in untapped (task 1), incompletely drained (task 2), and new pool (task 3) reservoirs have proceeded along three individual lines of focus: (1) playwide identification and delineation of incremental recovery opportunities, (2) characterization of heterogeneity and delineation of incremental recovery opportunities in Rincon field reservoirs, and (3) characterization of heterogeneity and delineation of incremental recovery opportunities in T-C-B field reservoirs. Results from each of these three study areas will be discussed as separate topics in this report.

Summary of Year 2 Results

Work performed during this reporting period (October 1993-October 1994) consisted of Phase II tasks associated with delineation of incremental recovery opportunities in the Frio reservoirs that were chosen for detailed study during Phase I (Table 3). Screening of reservoirs from each field to determine the best candidates for recompletion and infill potential was completed early in the second project year. The four representative reservoirs selected for detailed studies are the Frio D and Frio E zones in Rincon field and the Scott/Whitehill and 21B zones in T-C-B field. Delineation of untapped reservoirs (task 1), incompletely drained/compartmentalized reservoirs (task 2), and new pool reservoirs (task 3) in these zones is in progress and is scheduled for completion at the end of project budget period 1, which coincides with the end of calendar year 1994.

In addition to specific project tasks, final revised versions of the annual contract report and a topical report were completed and submitted to DOE for publication and distribution. Two technical papers were prepared for presentation: one for the 1994 American Association of Petroleum

Table 3. 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 sub-intervals within the entire play.
2. Playwide evaluation of additional resource potential and assessment of remaining mobile 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 & 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.

Geologists Meeting in June and a second for the Gulf Coast Association of Geological Societies Meeting in October. A Bureau of Economic Geology Report of Investigations on playwide resource assessment and identification of remaining oil potential in the Frio Fluvial-Deltaic Sandstone Play entered final stages of preparation for publication. This report is scheduled to be published in early 1995. Three separate abstracts were also prepared, submitted, and accepted for presentation at the annual American Association of Petroleum Geologists meeting to be held in March of 1995. These abstracts highlight project results from playwide reservoir assessment and from initial reservoir characterization studies in each field area. A listing of these individual publications is included as Appendix A of this report.

Playwide Reservoir Studies

Reservoir engineering data from fields throughout the Frio Fluvial-Deltaic Sandstone Play trend were grouped within middle Frio, lower Frio, and upper Vicksburg stratigraphic subdivisions in order to characterize general reservoir heterogeneity, evaluate production behavior, and assess remaining resource potential within each of these stratigraphic intervals. The stratigraphic positions of individual fields and reservoir units within the context of the entire Frio-Vicksburg productive reservoir 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. 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.

Overall estimates of the remaining mobile oil resource in reservoirs from middle and lower Frio stratigraphic intervals throughout the play trend in South Texas indicate that at least 40% of the original oil in place, representing nearly 1.5 Bbbl of remaining mobile oil are still present in these reservoirs.

Field Characterization Studies

Rincon Field

A digital data base for Rincon field consisting of log curves for nearly 200 wells was edited and updated to include production data and reservoir tops, log facies type, thicknesses, net sandstone, percentage sandstone, and core porosity, permeability, and water saturation for individual reservoir zones. Digitized log data were depth adjusted to correspond with core analysis data and normalized to account for baseline drift in SP response. Maps illustrating the distribution of oil production and initial flow potential were generated for the three major reservoir intervals in Rincon field; the Frio D, E, and G sandstones. Maps of net sandstone thickness, percentage sandstone, and log facies were constructed for separate reservoir subunits within each of the three zones and compared with cumulative-oil-production and initial-flow-rate maps to identify differences in sandstone depositional styles and production behavior and to identify zones with significant stratigraphic heterogeneity and a high potential for containing unproduced oil.

Delineation of additional oil resources in two Frio reservoir zones in Rincon field is currently being evaluated through the analysis of abundant wireline core data, description of available whole core, facies mapping, and the development of petrophysical models. Wireline core data within the Frio D and E zones from more than 100 wells in the Rincon field study area were grouped by reservoir subunit and by reservoir facies in order to identify variations in measured attributes between individual reservoir zones and characterize heterogeneity within these reservoir zones. Descriptions of whole core from two wells were completed and samples representing various reservoir facies were selected for further petrographic study and for special core analysis. Mercury injection capillary pressure measurements, formation resistivity measurements *(m)*, and basic core flood tests (with end-point relative permeability) are being performed on samples to obtain measurements on irreducible water saturation and residual oil saturation, as these attributes are critical to our delineation of oil in place and remaining mobile oil. The details of the internal physical architecture in the Frio D and E reservoir zones will be used to identify the dimensions of individual flow units, delineate remaining recoverable reserves, and identify specific incremental recovery opportunities.

T-C-B Field

Major efforts in T-C-B field during the year have focused on fieldwide reservoir studies and the development of a detailed, subregional stratigraphic framework for the productive Frio reservoir interval. Stratigraphic correlation of the Frio reservoir section was performed using geophysical well logs from key wells within and adjacent to the T-C-B study area, and several cross sections were constructed to document general reservoir sandstone geometry and identify significant bounding surfaces between and within reservoir zones. Two different sandstone architectural styles were identified, and representative reservoirs from each, the Scott/Whitehill and 21-B zones, were selected for detailed study. Further correlations and detailed mapping to delineate flow unit boundaries and identify individual reservoir compartments within each reservoir zone are currently in progress.

Additional work conducted during this project year in T-C-B field included continued data base preparation to support reservoir engineering tasks associated with volumetric calculations. Available log curves from more than 50 wells in the study area were digitized for log analysis and calculation of key petrophysical properties of porosity, permeability, and oil saturation. More detailed production data were obtained from the field operator to enable more accurate calculations of drainage from identified reservoir compartments. Available sidewall core samples were inventoried, and a limited number of samples were selected for petrographic study.

RESERVOIR CHARACTERIZATION METHODOLOGY

Overview of Field Screening Procedures and Reservoir Selection

Data were screened from productive Frio reservoirs distributed among fields along the entire play trend, which extends from Starr County northeastward to Jim Wells and Nueces Counties, in South Texas (Figure 4). Initial data screening was limited to the subset of fields that have reservoirs that have produced more than 1 MMSTB from the Frio and have wells currently producing oil from Frio zones. Geologic, engineering, and production data including the number and sizes of individual Frio reservoirs, cumulative past production, and the present status of Frio production were summarized and compared between fields. Preliminary estimates of potential infield reserve growth were based on analysis that included calculating completion densities for individual fields and determining current reservoir recovery efficiencies.

Criteria that formed the basis for field selection are summarized in Table 4. Fields that contain reservoirs with large producing areas and numerous wellbores with a relatively wide completion spacing present the best potential for containing bypassed and untapped reservoir compartments. The availability of abundant high-quality geologic, geophysical, and production data, including conventional core and core analysis data, modern well logs, and 3-D seismic coverage, will provide the best chance of success for identifying additional reserve potential through advanced reservoir characterization techniques. 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 areas with the best potential for near-term implementation of recommendations resulting from this project. The two field candidates chosen for further study, Rincon field, located in Starr County, and Tijerina-Canales-Blucher field, in Jim Wells County, were selected on the basis of our screening criteria and preliminary assessments of additional reserve growth potential (Table 5).

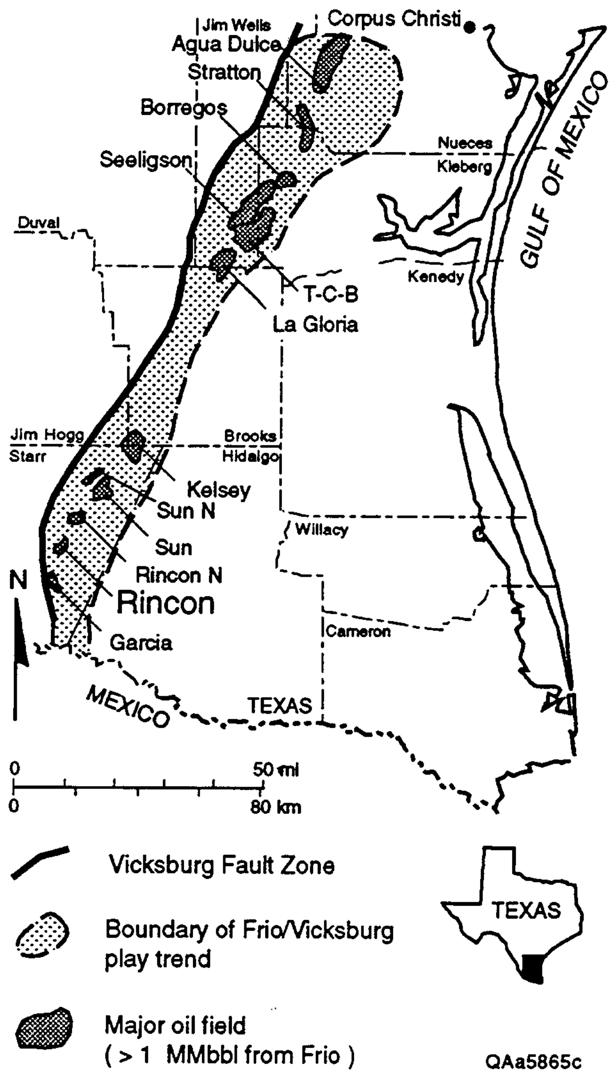

Figure 4. Map of south Texas showing location of fields within the Frio Fluvial-Deltaic Sandstone Play along the Vicksburg Fault Zone. Fields shown include those which have produced more than 1 million Bbls (Modified from Galloway and others, 1983, and Kosters and others, 1989).

Table 4. Key criteria for reservoir selection.

KEY CRITERIA	*BENEFITS*
1. Reserve growth potential of unrecovered resources and declining well counts	• Target large volumes of mobile oil resources in greatest danger of remaining undeveloped
2. Large producing area, limited well completion density	• Increased opportunity for infill potential
3. Amount, quality, and type of field data	• Provides resources to perform detailed reservoir characterization studies, identify untapped and incompletely drained compartments, and quantify additional recoverable resources
4. Stratigraphically complex and structurally simple field area	• Greater reservoir heterogeneity, more likely to contain unproduced compartments
5. Current drilling activity within reservoir	• Indication of operator cooperation and commitment to further drilling, • Presents opportunities for study results to provide near-term impact on development

Table 5. Summary table of South Texas fields selected for detailed study.

Basic Information:	RINCON FIELD	T-C-B FIELD
Operator:	Conoco	Mobil
Discovery Year:	1939	1939 (by Shell)
Total Acres:	20,520	4800
Wells:	640+	80
Reservoir Sands:	30	18
Sands > 1 MMBO	14	8
Depth Interval:	3000-5000 ft	5500-7700 ft
Cumulative Oil Prod:	65 MMBO	22.9 MMBO
Active Completions:	25 oil, 30 gas	10 oil, 23 gas
Current Rates:	373 bopd 4576 mcf/d	300 bopd 16,000 mcf/d
Available Field Data:		
Study Area	5400 acres (northern field area)	3500 acres (1 lease)
Number of Wells	173	85
Whole Core	300 ft core	No core
Other Core Data	Analyses from 100+ wells Additional sidewall cores	Limited analyses Sidewall cores from 13 wells

Genetic Sequence Analysis of Frio Fluvial-Deltaic Reservoirs

The development of a detailed regional stratigraphic and structural context for a reservoir provides an important framework that is useful in delineating the structure of reservoir flow units and also provides a means of transporting results of reservoir studies to other fields in analogous stratigraphic settings. Sequence stratigraphy is becoming increasingly more common as a tool in the detailed reservoir characterization of mature fields. Construction of a reservoir framework at the sequence and parasequence scales provides 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 (Galloway, 1977, 1982, 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 of South Texas. The stratigraphic position of an individual reservoir within the overall depositional stacking pattern and larger scale genetic sequence (Galloway, 1989a) provides important controls on hydrocarbon production, recovery efficiency, heterogeneity style, and the potential for compartmentalization of additional oil resources. Specific architectural styles of reservoirs deposited in fluvial-deltaic environments are a function of varying rates of sediment supply, subsidence, eustatic sea-level change, and other extrabasinal factors (Miall, 1988). Different rates of coastal-plain aggradation control stacking geometries and connectivity of channel sandstones. Laterally stacked and connected channel systems are developed during slow net aggradation (low accommodation), whereas vertically stacked and isolated channel systems are indicative of relatively rapid aggradation (high accommodation) (Kerr and Jirik, 1990).

Reservoirs within the entire producing depth interval in the Frio Fluvial-Deltaic Sandstone play were evaluated with respect to their genetic depositional context in order to assess the controls of stratigraphic position on petrophysical attributes, hydrocarbon production behavior, degree of heterogeneity, and the potential for incremental reserve growth. Further integration of past reservoir production behavior with detailed studies of geologic facies heterogeneity within individual reservoirs may be used to identify the location of significant additional reserves in unproduced reservoir compartments in reservoirs throughout this play that may have a large remaining oil resource and face premature abandonment. The methodology used here to assess remaining oil resources within the Frio Fluvial-Deltaic Sandstone play and to identify locations of additional recoverable oil within selected producing reservoirs has wide applicability in other heterogeneous fluvial-deltaic reservoirs within and outside the Frio play in South Texas.

The identification of facies and resulting patterns of reservoir architecture and heterogeneity of the reservoirs selected for detailed study in Rincon and T-C-B fields will also be evaluated within the context of a well-defined regional sequence-stratigraphic framework. This will provide a critical means to predict the distribution and continuity of permeable zones in Frio reservoirs in other fields within the Vicksburg Fault Zone play and ultimately provide analogs to other reservoirs deposited in similar fluvial-deltaic settings.

PLAYWIDE RESERVOIR STUDIES

L.E. McRae and M.H. Holtz

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 6.

Table 6: 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

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 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 5). 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 7.

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 remaining

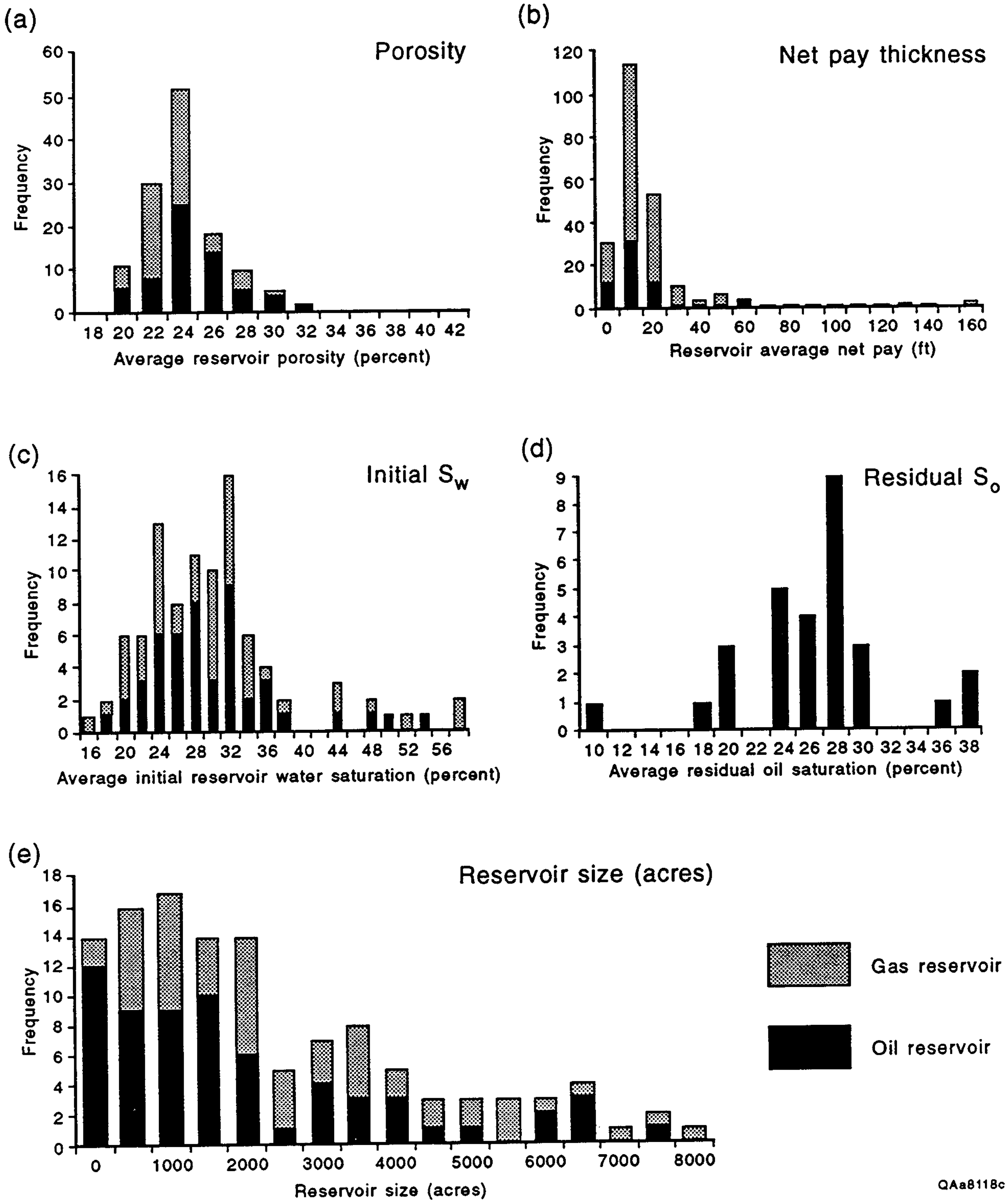

Figure 5. Histograms illustrating distributions for values of porosity (A), initial water saturation (B), residual oil saturation (C), net pay (D), and area (E) from reservoirs throughout the Frio Fluvial-Deltaic Sandstone Play in South Texas.

throughout the play was based on these probability distributions (Figure 6). Oil reservoirs in the play are estimated to contain a conservative estimate of 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.

Table 7. 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

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

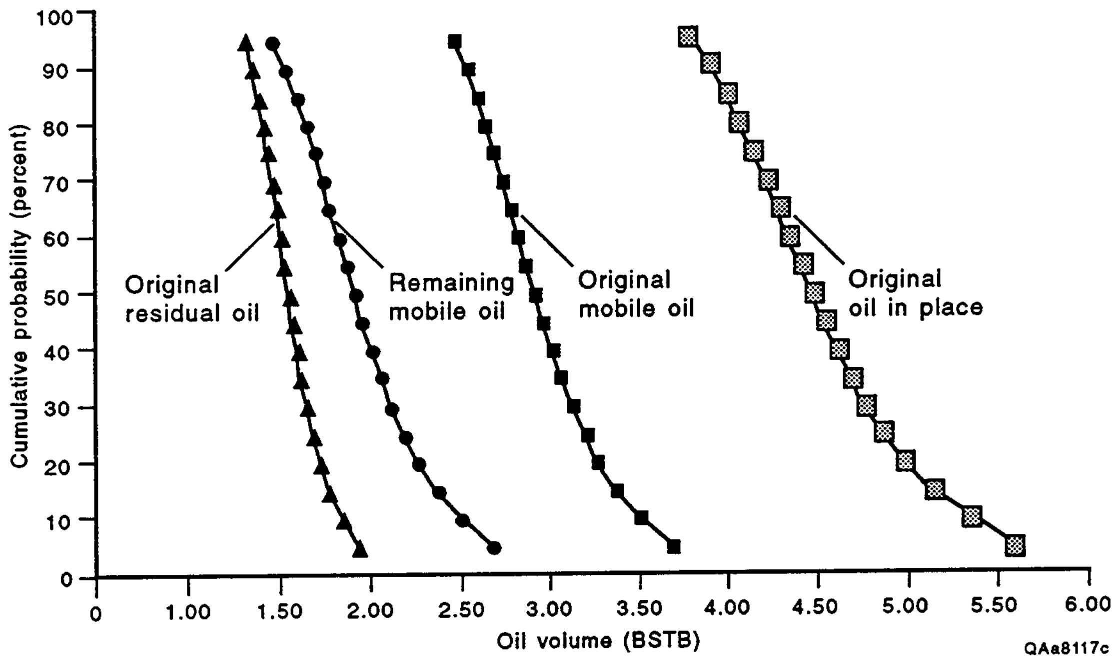

Figure 6. Probability distribution curves illustrating the cumulative probability of original oil in place, original residual oil, original mobile oil, and remaining mobile oil for the Frio Fluvial/Deltaic Sandstone play.

Vicksburg Fault Zone, a major down-to-the-coast listric normal growth fault system that parallels the Gulf coastline for over 100 mi (Figure 4). 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 fault 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 7). 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 8). 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 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 9). In general, lower Frio sands represent deltaic facies of the ancestral Norias delta system, and middle and upper Frio sands 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.

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 10). Reservoir sandstones within stratigraphic intervals exhibiting each sediment stacking style possess distinctive characteristics that control their producibility, determine

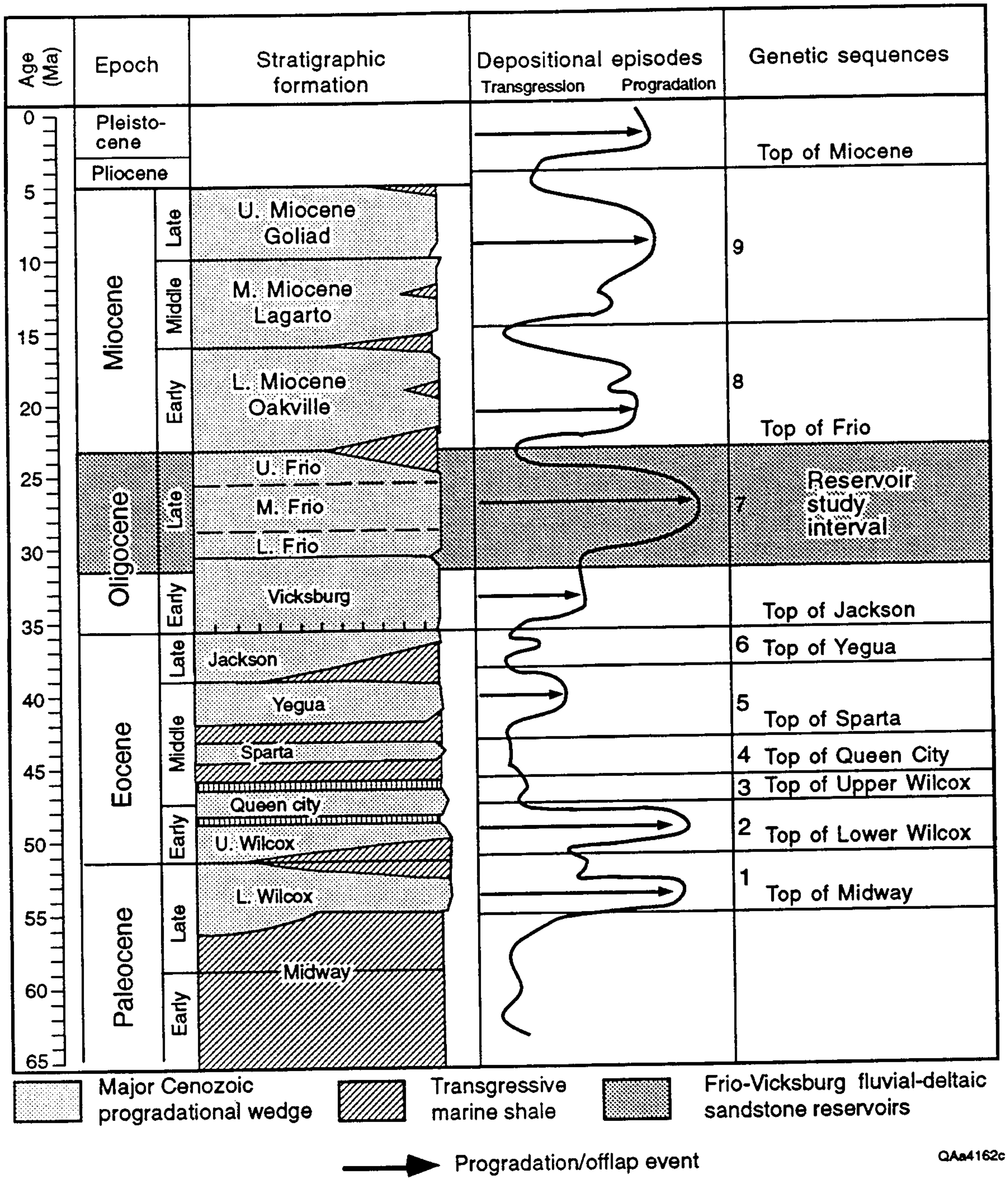

Figure 7. Stratigraphic column of Cenozoic sediments of the South Texas Gulf Coast. The sedimentary succession has been divided into a series of large-scale depositional episodes that represent major periods of progradation that occurred throughout the Cenozoic (Galloway, 1989b). Reservoirs in the Frio Fluvial/Deltaic Sandstone play are part of a larger Frio-Vicksburg genetic sequence.

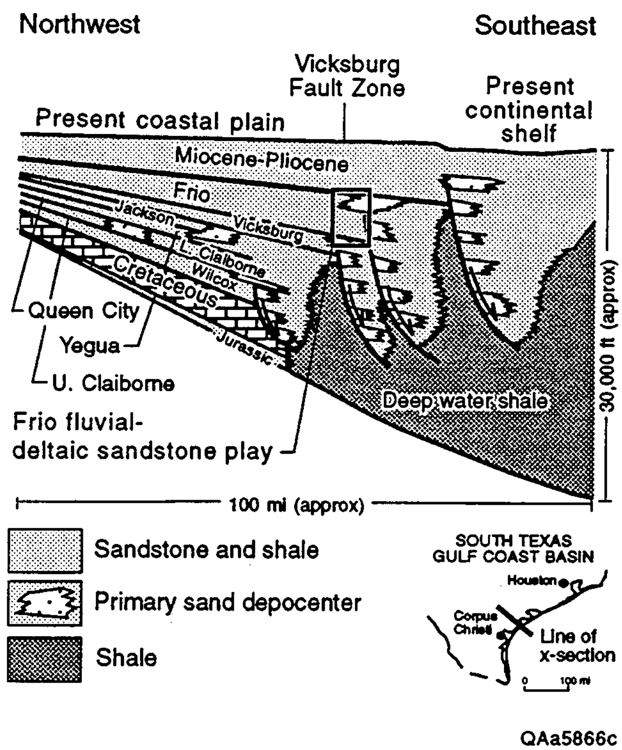

Figure 8. Schematic cross section of the South Texas Gulf Coast Basin. Modified from Bebout and others (1982).

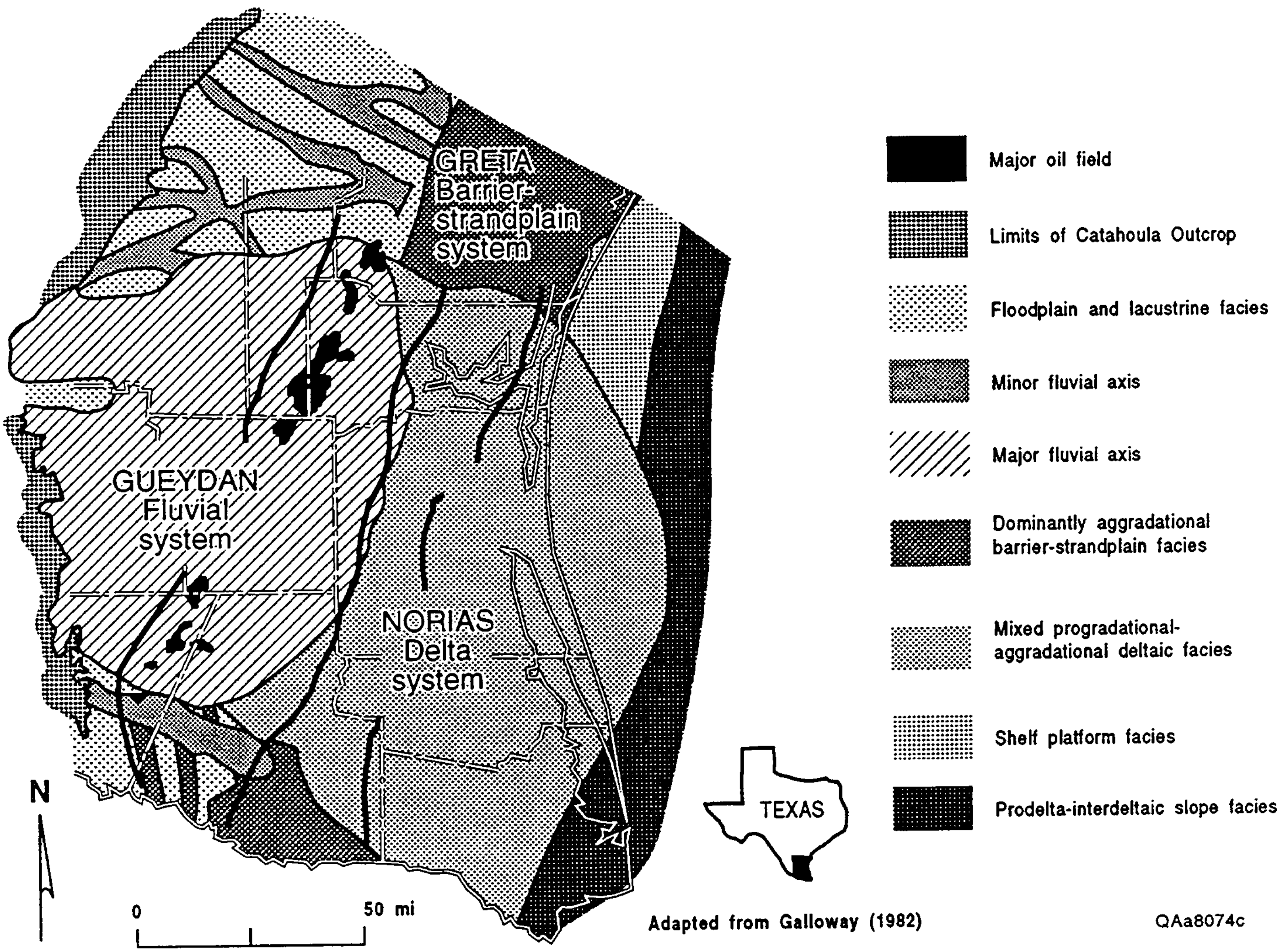

Figure 9. General distribution of the Norias delta and Gueydan fluvial depositional systems responsible for deposition of the Frio stratigraphic unit. The Frio sediments in the vicinity of the Vicksburg Fault Zone were primarily deposited in moderate to high sinuousity mixed-load stream environments of the Gueydan Fluvial system. (Map distribution from Galloway and others, 1982).

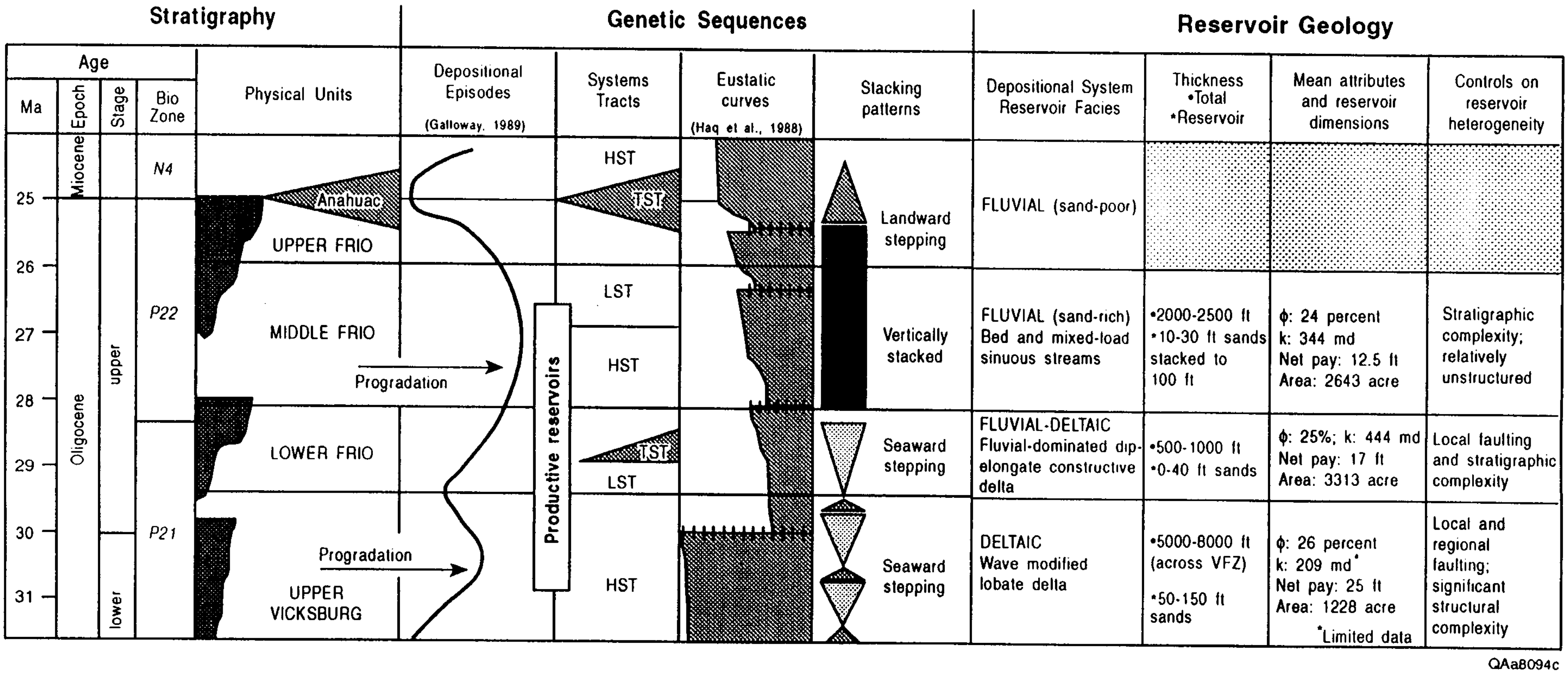

Figure 10. Stratigraphic subdivisions for reservoirs in the Frio Fluvial-Deltaic Sandstone Play and summary of genetic sequence context, reservoir characteristics, oil production, and estimates for remaining oil potential in middle and lower Frio reservoirs.

their potential for incremental recovery, and dictate which strategies should be used to best identify locations of remaining mobile oil in undeveloped compartments.

Sediments in 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 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.

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. 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 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 over 1 MMBO (Figure 4) were identified as belonging to the middle Frio, lower Frio, or upper Vicksburg stratigraphic interval (Figure 11, Table 8). 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 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 focuses 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

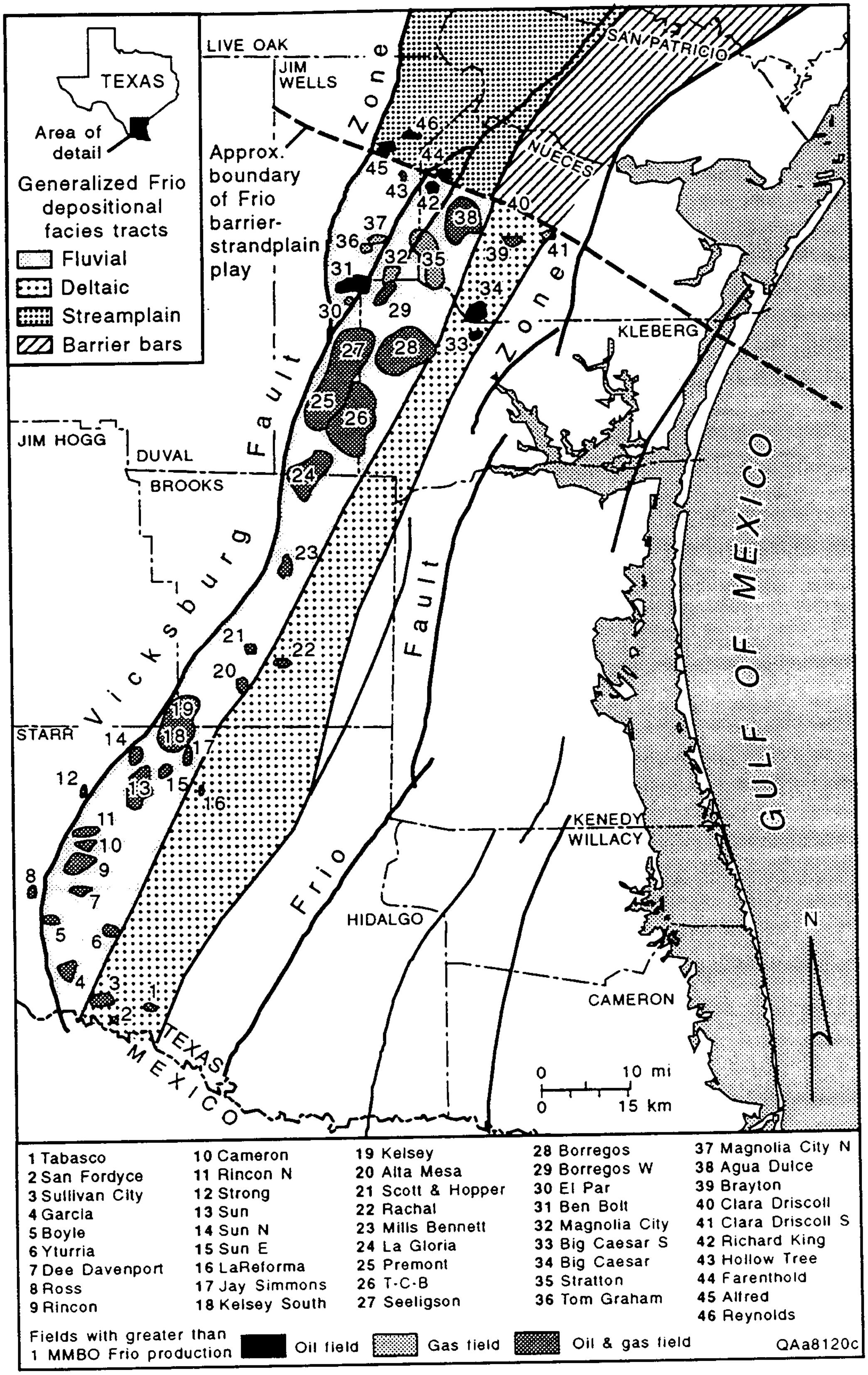

Figure 11. Location map of major oil and gas fields in the Frio Fluvial-Deltaic Sandstone Play in South Texas. Reservoirs from these fields have been subdivided according to stratigraphic position and depositional facies into middle Frio (fluvial) reservoirs and lower Frio (fluvial-deltaic) reservoirs to identify differences in heterogeneity style and better estimate remaining oil potential in each type of reservoir facies.

Table 8. List of major oil fields in the Frio Fluvial-Deltaic Sandstone Play. Map number refers to figure 11.

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	LF	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		LF	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	LF	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	Borresgos 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	LF	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	LF	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

those reservoirs in the overlying Frio section (Figure 12). 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 sand 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 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 12). 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

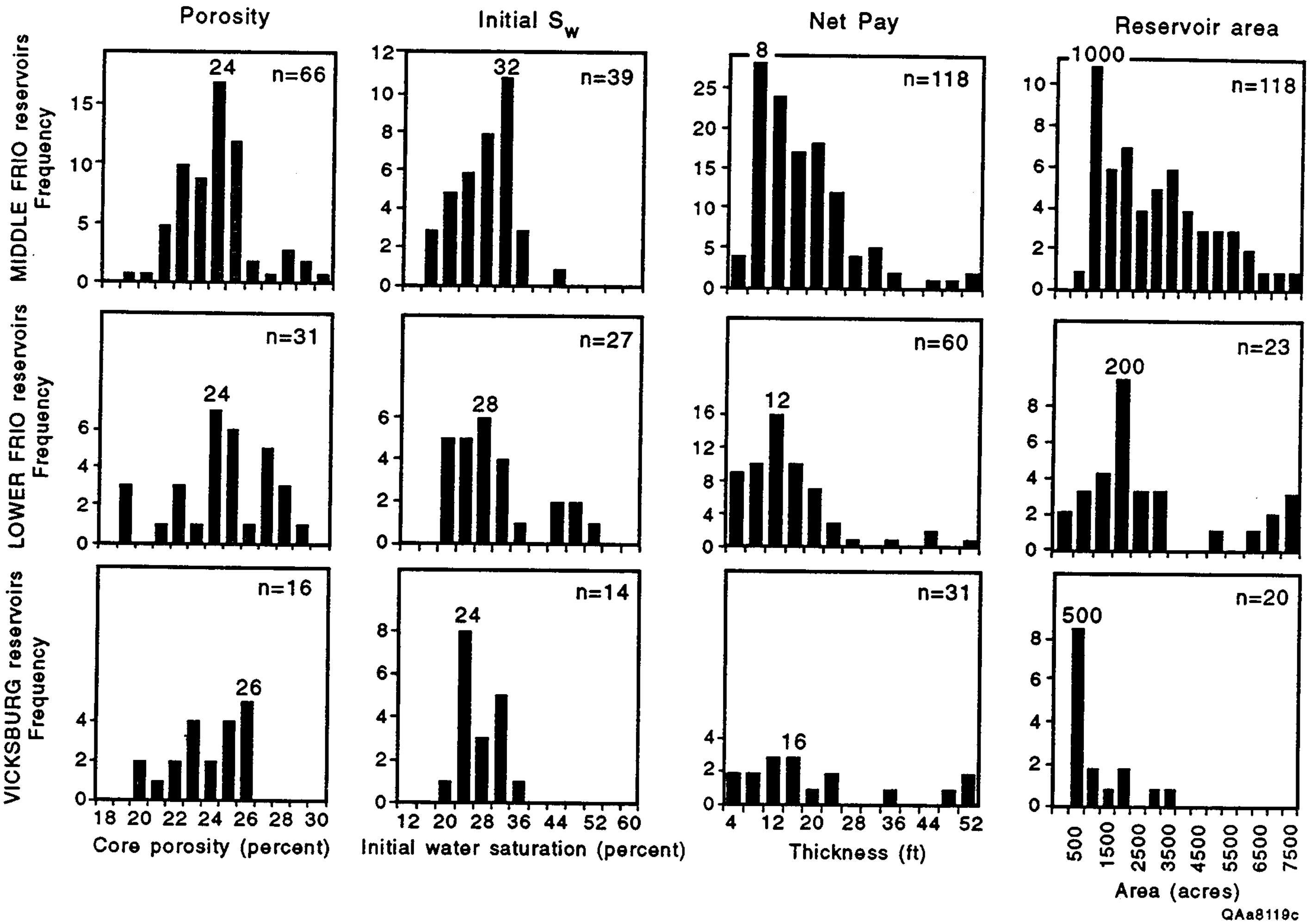

Figure 12. Cumulative frequency histograms illustrating the differences in the distribution of values of porosity, initial water saturation, net pay, and reservoir area for middle Frio, lower Frio, and Vicksburg reservoir sandstones in the Frio Fluvial-Deltaic Sandstone Play.

Frio reservoir sandstones, although the distributions of values for these data are distinctive for each (Figure 12).

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 over 40% of the OOIP, are still present in these reservoirs (Figure 13). 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 as long production histories because the shallower Frio section was the preferred focus of most early Frio reservoir development.

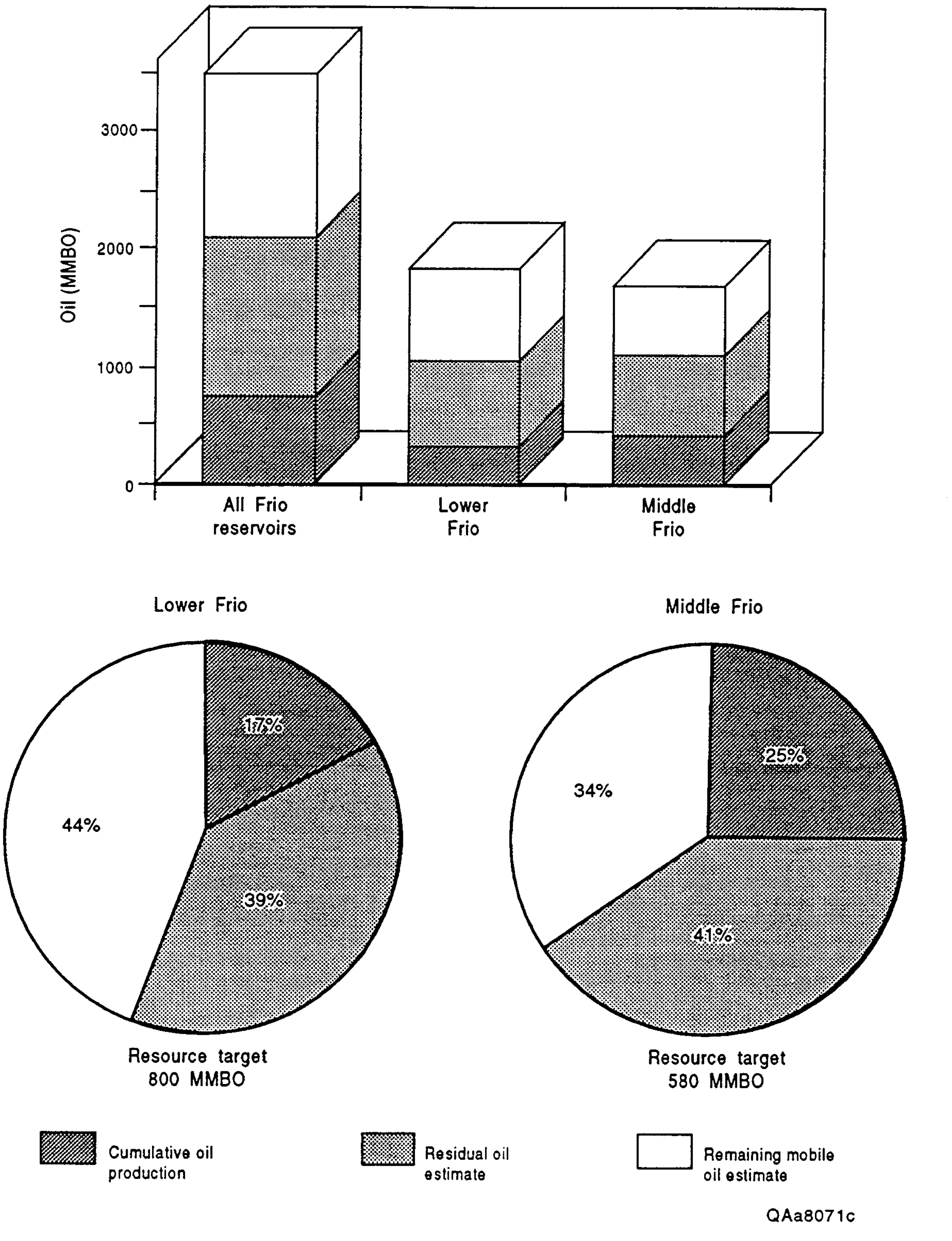

Figure 13. Distribution of the location of oil resources within reservoirs of the Frio Fluvial-Deltaic Sandstone Play in South Texas. Nearly one billion barrels have been recovered in the play, but nearly two thirds of the estimated original-oil-in-place, including more than 1.5 BBbls of mobile oil, remain in the reservoirs.

RINCON FIELD RESERVOIR STUDIES

L.E. McRae

Objectives and Methodology

Preliminary studies completed during Phase I and the first project year consisted of a thorough evaluation of available engineering and geological data from Frio reservoirs in the Rincon field study area. Engineering data were used to determine completion density, assess past production behavior, including a reservoir's response to waterflooding, and estimate overall recovery efficiency. Reservoir mapping and stratigraphic log correlations were used to describe general depositional styles within the productive 1,000-ft-thick stratigraphic interval and assess the potential for compartmentalization of significant volumes of unrecovered oil. Evaluation of production histories for important Frio oil reservoirs was integrated with preliminary studies of facies architecture to identify zones with high potential for containing compartments with unproduced oil, and reservoir zones were prioritized for incremental reserve growth opportunities. Data from the two most prolific reservoirs in the field, the Frio D and E sandstones, were selected to be the focus of Phase II detailed characterization and delineation studies.

Preliminary reservoir delineation efforts during the early part of Phase II work in Rincon field included refinement of the stratigraphic framework of the productive reservoir section and an assessment of the stratigraphic distribution of remaining oil potential within the field study area. Reservoir data were further evaluated to identify relationships between stratigraphic position and porosity and permeability characteristics of selected reservoir sandstones and their ability to produce hydrocarbons. Estimates of remaining oil potential in the selected D and E reservoir zones based on preliminary reservoir studies were calculated to demonstrate particularly significant potential remaining in the Frio D reservoir zone. A summary of key strategies adopted during this phase of the study is provided in Table 9.

Phase II reservoir characterization studies in the Frio D and E reservoir zones are currently in their final stages as this second project year comes to a close. Tasks associated with the delineation of specific volumes of additional recoverable oil in the highly prospective Frio D sandstone zone are also

Table 9: Field-scale reservoir characterization strategies.

Field-scale reservoir characterization
Goals:
• Characterize reservoir variability and degree of heterogeneity.
• Identify zones with significant reservoir heterogeneity and a high potential for containing unproduced oil.
Methodology:
• Stratigraphic log correlations, reservoir mapping, analyses of petrophysical and production data.
• Assess differences in sandstone depositional styles and production behavior to evaluate potential for compartmentalization of significant volumes of unrecovered oil.

in progress and are scheduled for completion by the end of calendar year 1994. Identification of reservoir heterogeneity and controls on oil production is being pursued through the mapping and evaluation of oil production trends, net sandstone isopach, and electric log facies. Results from facies and net sandstone thickness mapping of individual reservoir subunits have been incorporated with analysis of abundant petrophysical data from wireline cores to identify facies-specific relationships between porosity and permeability. Delineation of additional oil resources will incorporate results from petrographic studies and special core analysis of limited available whole core. A summary of essential tasks already completed and those in progress is provided in Figure 14.

A brief review of the geologic setting and development history of Rincon reservoirs is provided below, followed by more complete discussions on specific tasks and results from Phase II reservoir characterization and delineation studies completed during project year 2.

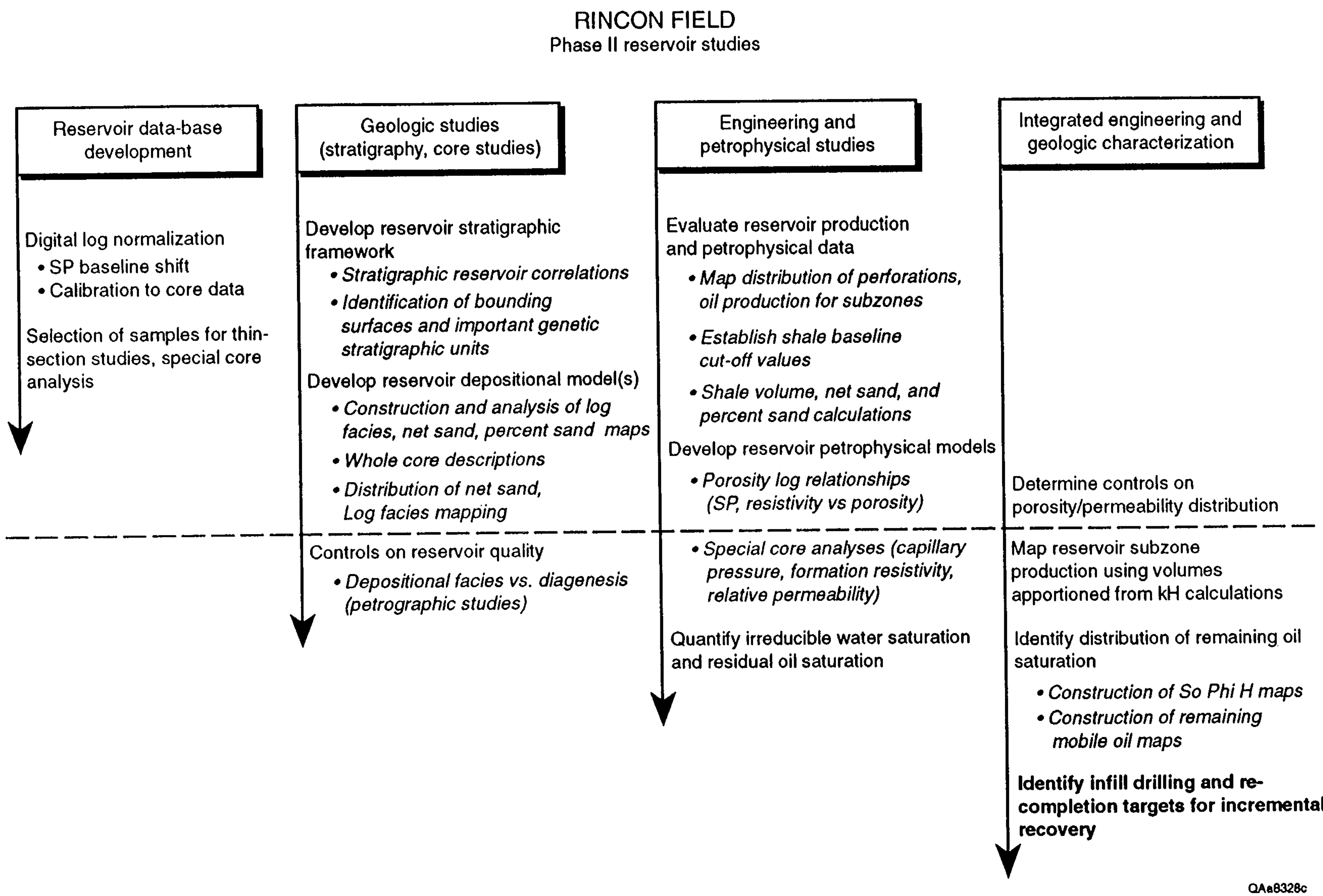

Figure 14. Flow chart summary of tasks completed and in progress for Phase II reservoir characterization of selected reservoirs in Rincon field. All those tasks located above the dotted line have been completed, and those located below the line are currently in progress and scheduled for completion at the end of calendar year 1994.

Location and Geologic Setting

Rincon field is located in eastern Starr County, Texas, roughly 120 mi southwest of Corpus Christi and approximately 20 mi north of the United States–Mexico border (Figure 15). The entire Rincon field area covers over 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 (Figure 16), and is limited to productive reservoir sandstones within the Frio section.

The general structure in the shallow Frio section 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 (Figure 17). 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 multilateral 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 sand 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.

Reservoir Development 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

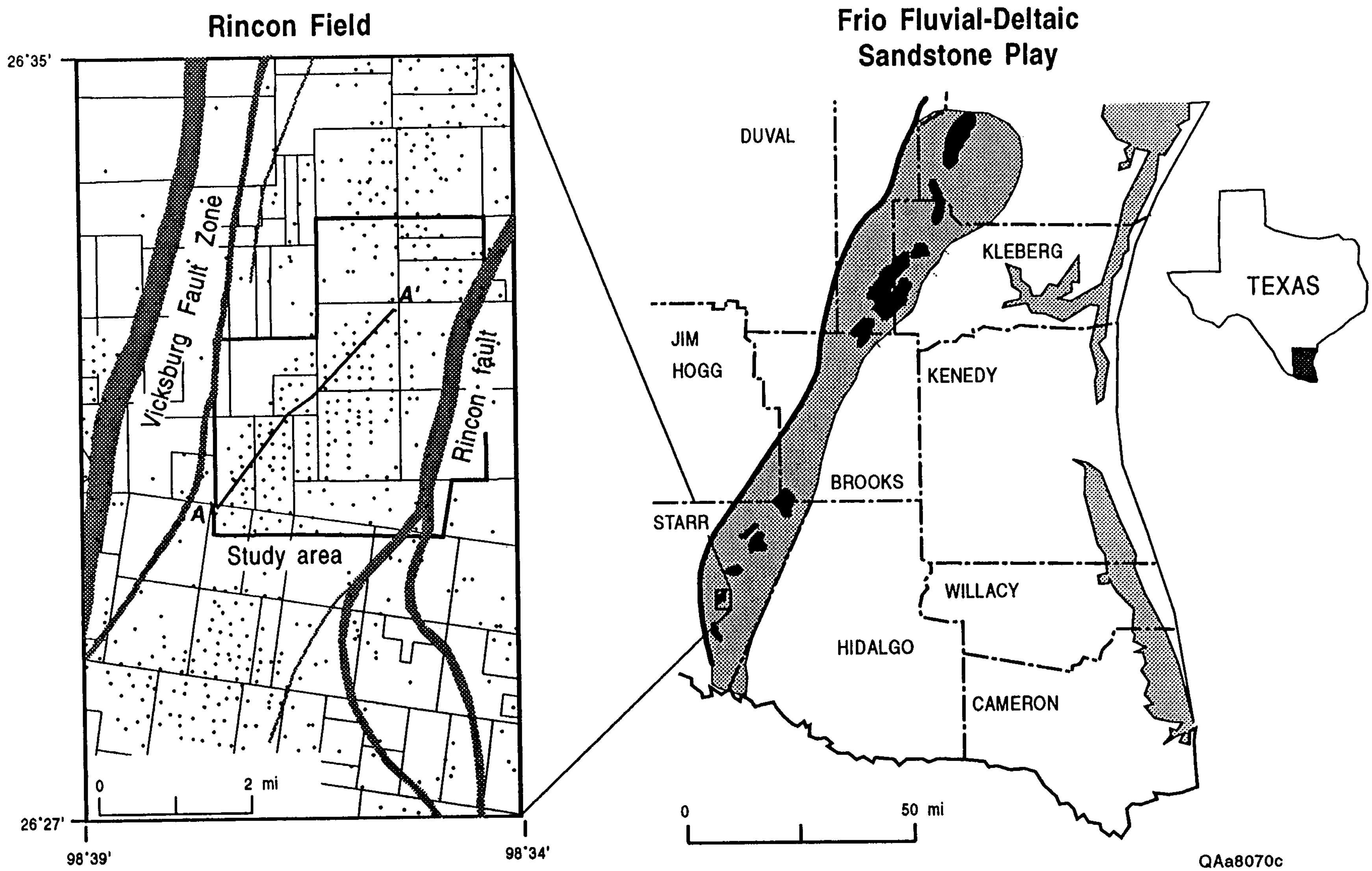

Figure 15. Location map of Rincon field within the Frio Fluvial-Deltaic Sandstone play, and area of field selected for detailed reservoir studies.

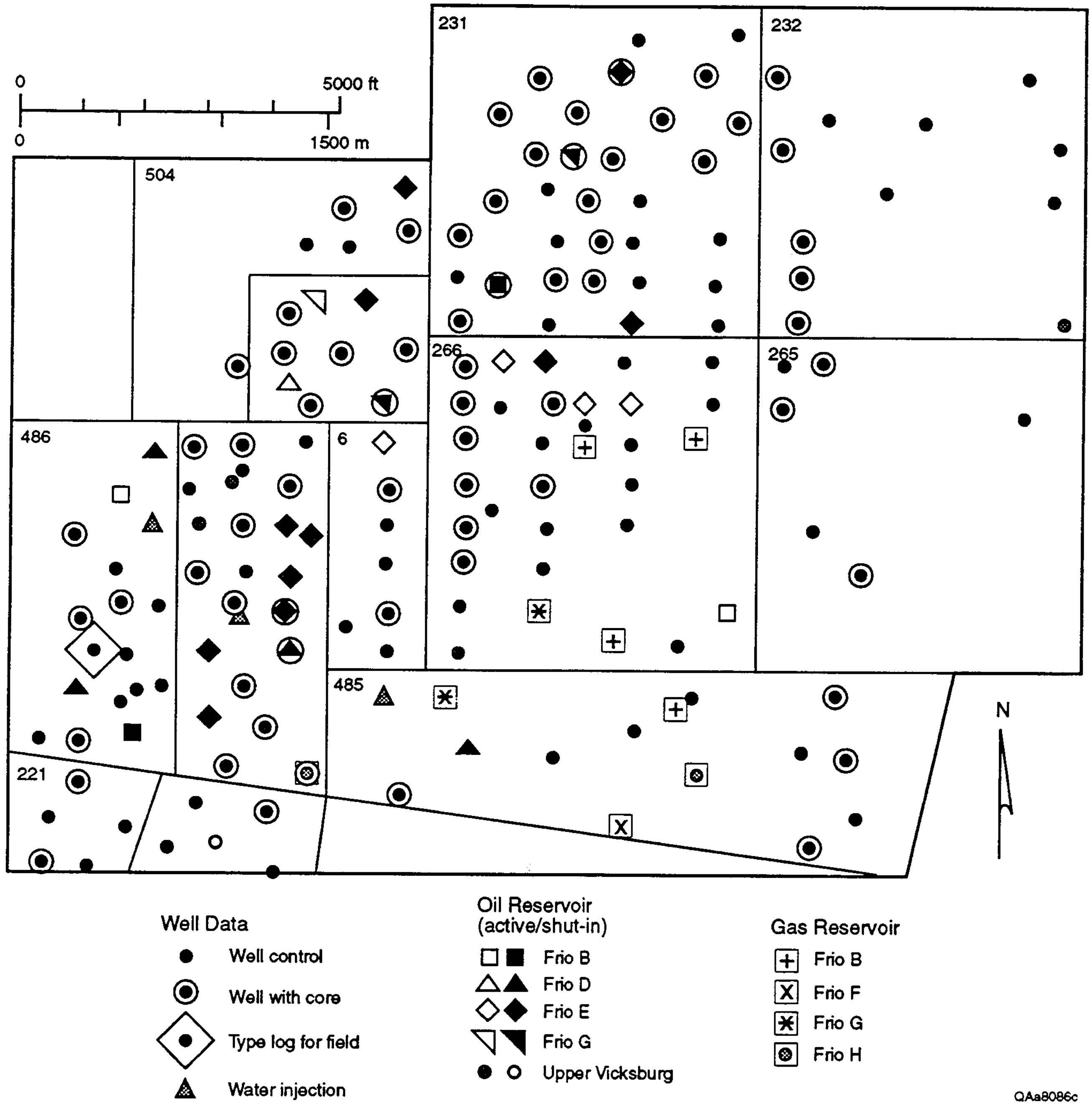

Figure 16. Detailed data map of area selected for study within Rincon field showing distribution of wells and available core data. The study is located within the central and northern portion of greater Rincon field and includes nearly 200 wells.

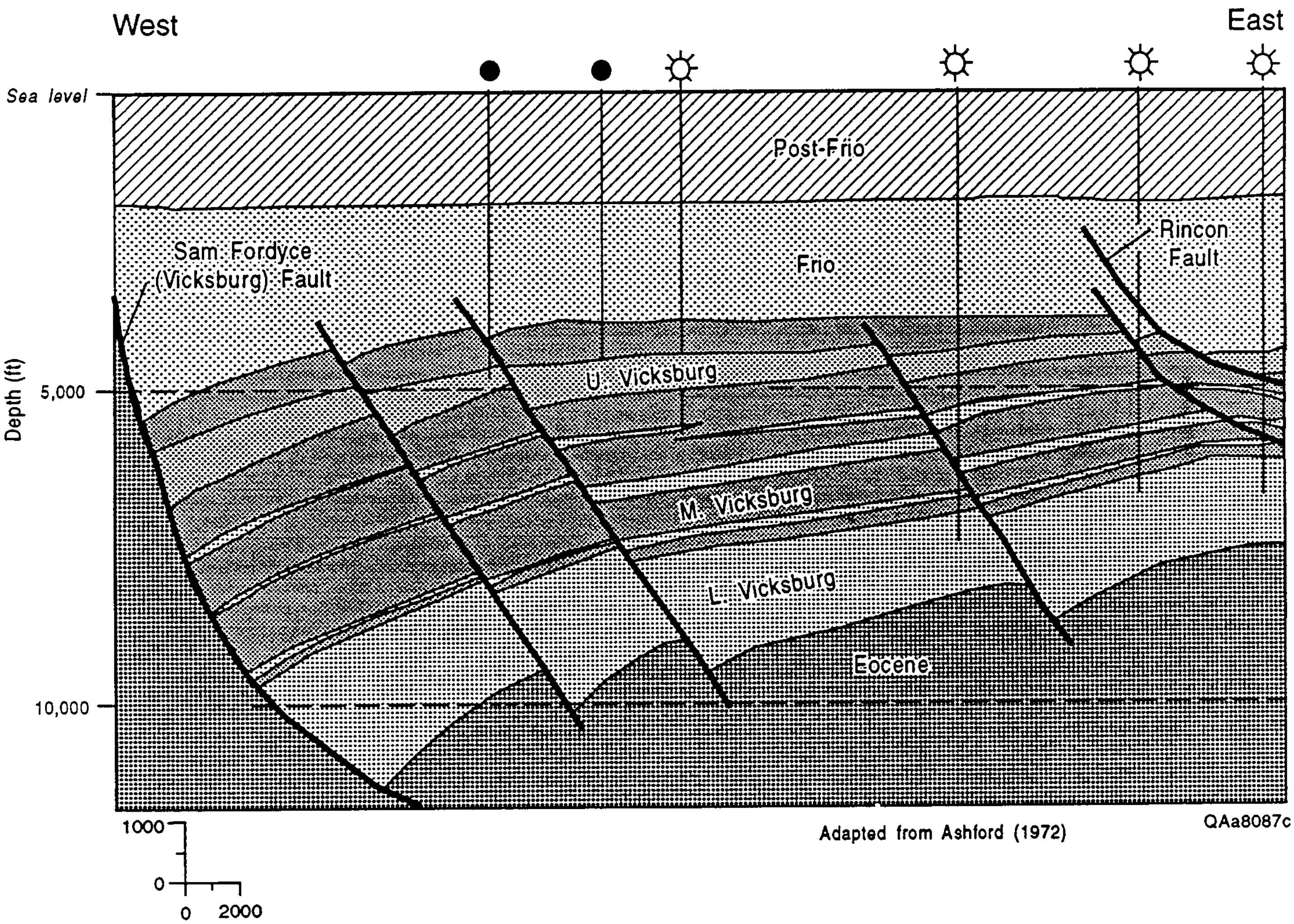

Figure 17. Generalized west to east cross-section through Rincon Field illustrating structural setting of a representative field in the Frio Fluvial-Deltaic Sandstone Play (adapted from Ashford, 1972).

production peaked in 1944, when production averaged approximately 7,300 bbl/d. Vicksburg production began in 1950, and since that time, most field exploration efforts have focused on prolific deeper Vicksburg structures. Production from 38 separate Frio reservoirs has yielded over 45 MMbbl of oil (Table 10).

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. 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. More complete documentation of reservoir development and discussion of production trends are presented in the annual report for project year 1 (McRae and others, 1994).

Table 10. Production summary and reservoir statistics for Rincon field.

General Field Information		*Reservoir characteristics :* ranges (mean)	
Discovery year:	1939	Porosity (%)	16-30% (26%)
Total acres:	20,520	Permeability (md)	41-1649 (80 md)
Wells:	640+	Initial Sw (%)	28-67% (42%)
Production characteristics		Net pay (ft)	5.0-20.4' (8.8)
Depth range of producing interval:	3,000-5,000 ft	Reservoir area (acres)	20-2200 (400)
Number of reservoirs	30		
Cum. oil production:	65 MMBO total 45 MMBO (Frio only)	*Fluid characteristics*	
No. of reservoirs with > 1 MMBO production	14	Oil gravity	40°-48 °API (42°)
Active completions: (as of 1991)	25 oil, 30 gas	Formation volume factor	1.14 - 2.05 (1.26)
Current flow rates: (as of 1991)	373 bopd 4576 mcf/d		

Stratigraphic Framework and Preliminary Resource Assessment of Rincon Reservoirs

Methods

The 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 on hydrocarbon production, recovery efficiency, heterogeneity style, and the potential for compartmentalization of additional oil resources. Twenty-four low-resistivity markers representing seven major (4th order) bounding surfaces and 17 secondary (5th order) surfaces in 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.

General Reservoir Stratigraphy

A typical log from the productive reservoir interval in Rincon field is shown in Figure 18. A representative southwest-northeast-trending strike section across the field area is illustrated in Figure 19. The Frio reservoir interval has been divided into 11 main zones designated A through K; the Frio-Vicksburg contact is taken to be the top of the L series sands (Figure 18). In Rincon field, productive Frio reservoirs occur within an interval of interstratified sandstones and mudstones that is approximately 800 to 1,000 ft thick. Laterally persistent low-resistivity surfaces interpreted to be floodplain or interdeltaic mudstones represent major 4th order bounding surfaces that separate the primary reservoir sandstone zones. These 4th order reservoir zones range from 50 to 100 ft thick.

Laterally persistent low-resistivity markers interpreted as 3rd order maximum flooding surfaces have been identified at the top of two sandstone units that represent retrogradational bar complexes (B and F units). The interpretation of these units as transgressive reworked bar sandstones is based on their electric log signatures and distribution as shown on net sandstone isopach and log facies maps. SP log profiles display an upward coarsening textural profile that is commonly diagnostic of bar facies, and isopach mapping reveals a strike-oriented distribution of these units. The development of

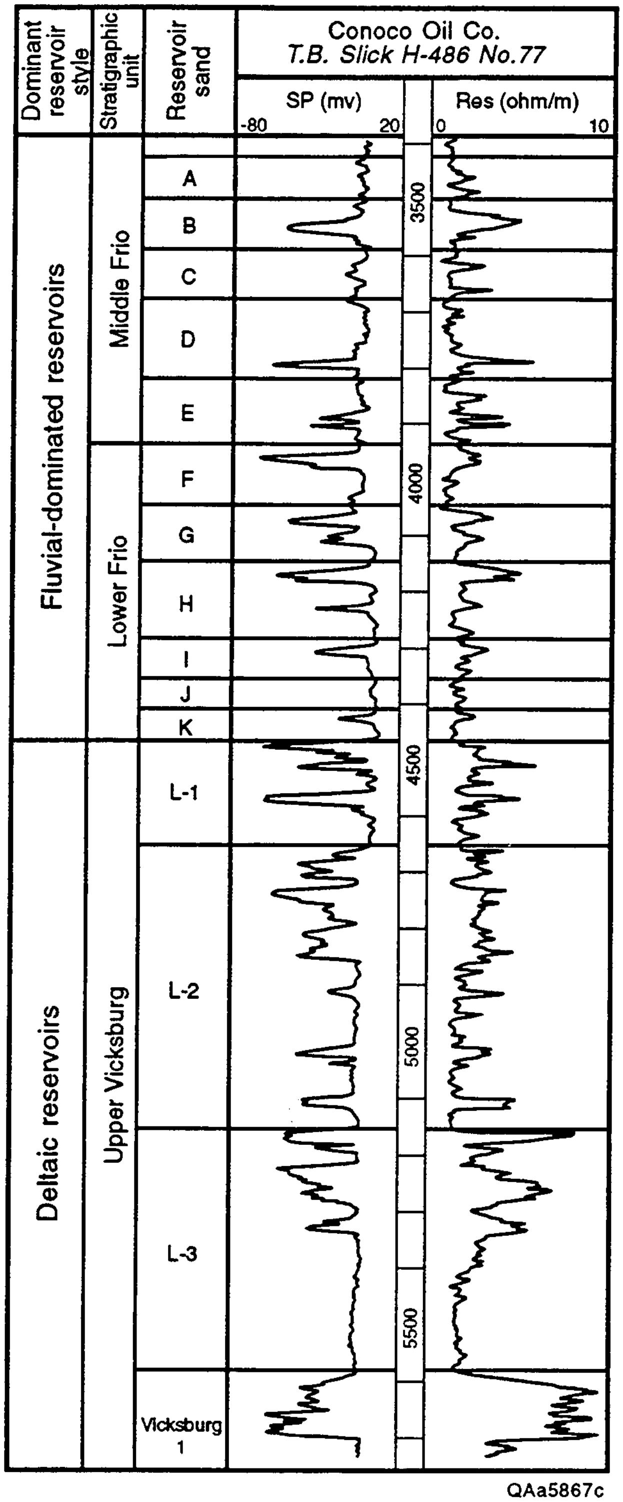

Figure 18. Representative log from Rincon Field illustrating general stratigraphy of the productive reservoir interval in the Frio Fluvial-Deltaic Sandstone Play.

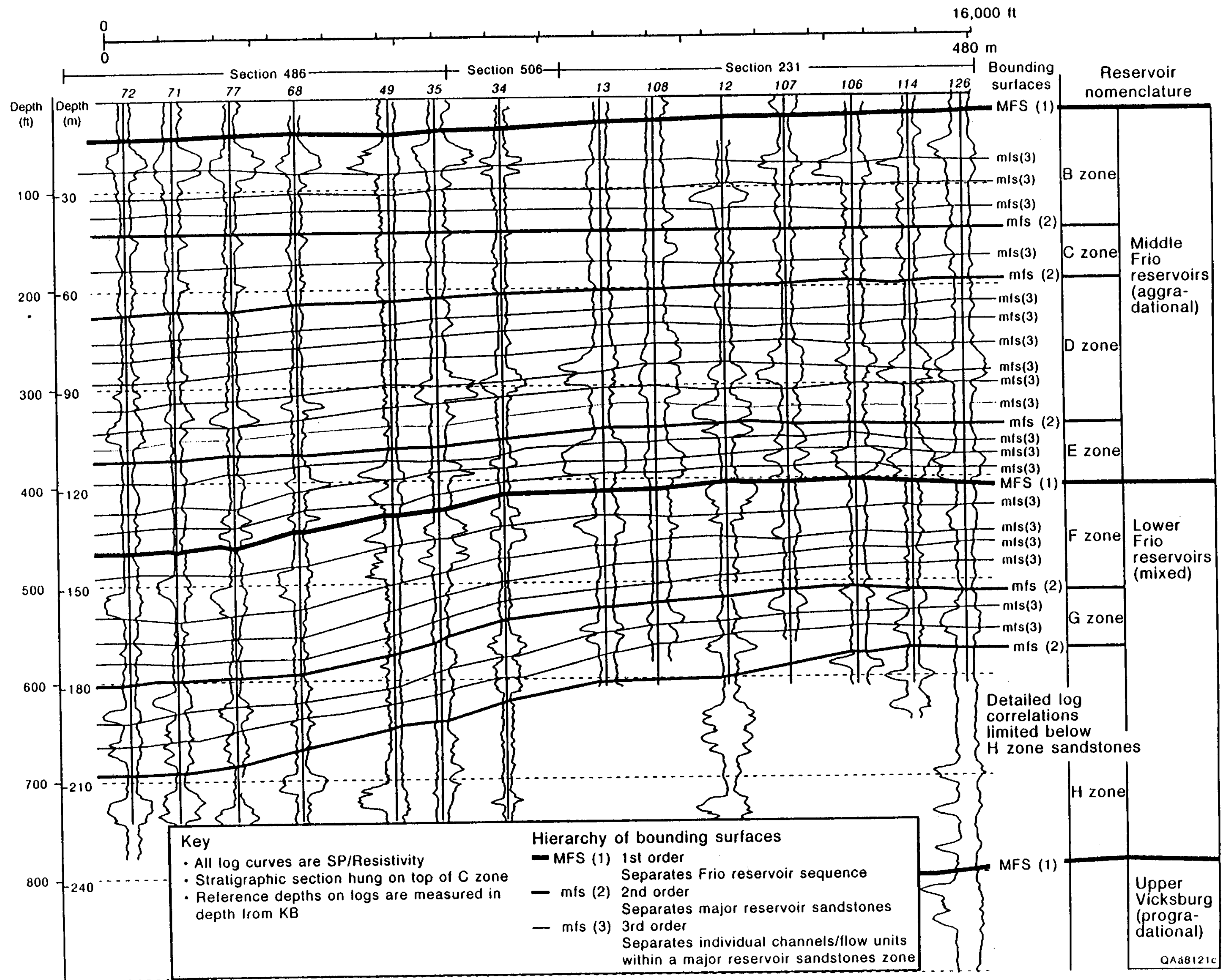

Figure 19. Regional stratigraphic strike cross-section across Rincon field study area. Line of section is identified as A-A' on the map shown on Figure 16. Datum is the top of Frio B sandstone, which also marks the top of the productive oil reservoir interval in the field.

these units may reflect brief periods of decreased aggradation that allows for minor marine transgression and subsequent reworking and redistribution of the sand previously deposited in dip-elongate channels by wave action. The development of these strike-oriented bar deposits appears to be limited, and isopach mapping indicates that they are laterally discontinuous. They do not form important oil reservoirs in Rincon field.

The F shale marker marks the division between lower and middle Frio reservoirs because it is located where a change in sedimentation style occurs from deposition of net progradational sandstone packages characteristic of Frio G–J sandstone units to purely aggradational sand deposition typical of Frio C, D, and E sandstone zones. 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 (5th order units) within each zone are commonly 5- to 30-ft-thick channel-fill units and have lateral dimensions ranging from 1,000 to more than 6,000 ft. The major cause for 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.

Depositional Systems and Reservoir Attributes

Upper Vicksburg reservoirs

Vicksburg reservoirs in Rincon field include the L sandstone unit shown at the base of the log interval illustrated in Figure 18. 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 (Figure 20). 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 targets for resource delineation and additional recovery in this project because their deposition was strongly influenced by faulting associated with

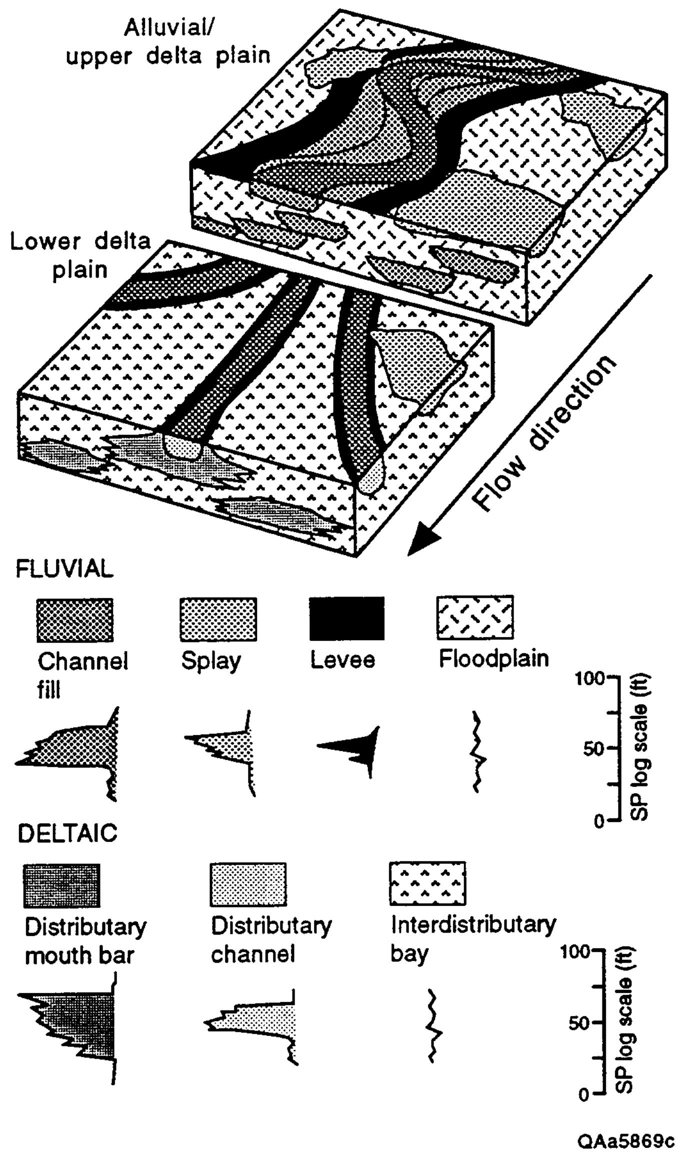

Figure 20. Schematic block diagram illustrating general 3-dimensional relationships and characteristic SP log responses in fluvial reservoir and non-reservoir facies (modified from Galloway, 1977).

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 Frio G–J (lower Frio) reservoir interval shown on the log in Figure 17 and the stratigraphic cross section in Figure 18 are interpreted to correspond to an interval of mixed progradational and aggradational sedimentation. The F shale marker 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 sand-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 dominant depositional pattern in the middle Frio interval in Rincon field is characterized by sedimentation dominated by fluvial aggradation (Figure 20). 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. The Frio C, D, and E sandstone zones (middle Frio) as identified in Figure 18 represent deposition in a purely aggradational setting.

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 that combine into a single large communicating reservoir (Figure 21). 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 the development of multiple reservoir compartments that may represent significant opportunities for additional recovery.

Reservoir attributes

Distributions of values for core porosity and permeability for reservoirs representing the upper Vicksburg, lower Frio, and middle Frio are illustrated in histograms shown in Figure 22. Deltaic reservoirs from the upper Vicksburg have distinctly lower porosity and permeability (mean ϕ = 20.3 percent, median k = 8.2 md) than Frio reservoirs (Figure 22), probably reflecting the interbedded sandstone/mudstone alternations characteristic of these stacked progradational units. Deltaic Vicksburg reservoirs are responsible for approximately 33% of the total oil production from Rincon field (Figure 23).

There are distinct distributions of reservoir porosity and permeability exhibited by core data from lower and middle Frio reservoir units (Figure 22). Channel sandstone reservoirs in the mixed progradational/aggradational lower Frio interval have higher porosity and permeability values

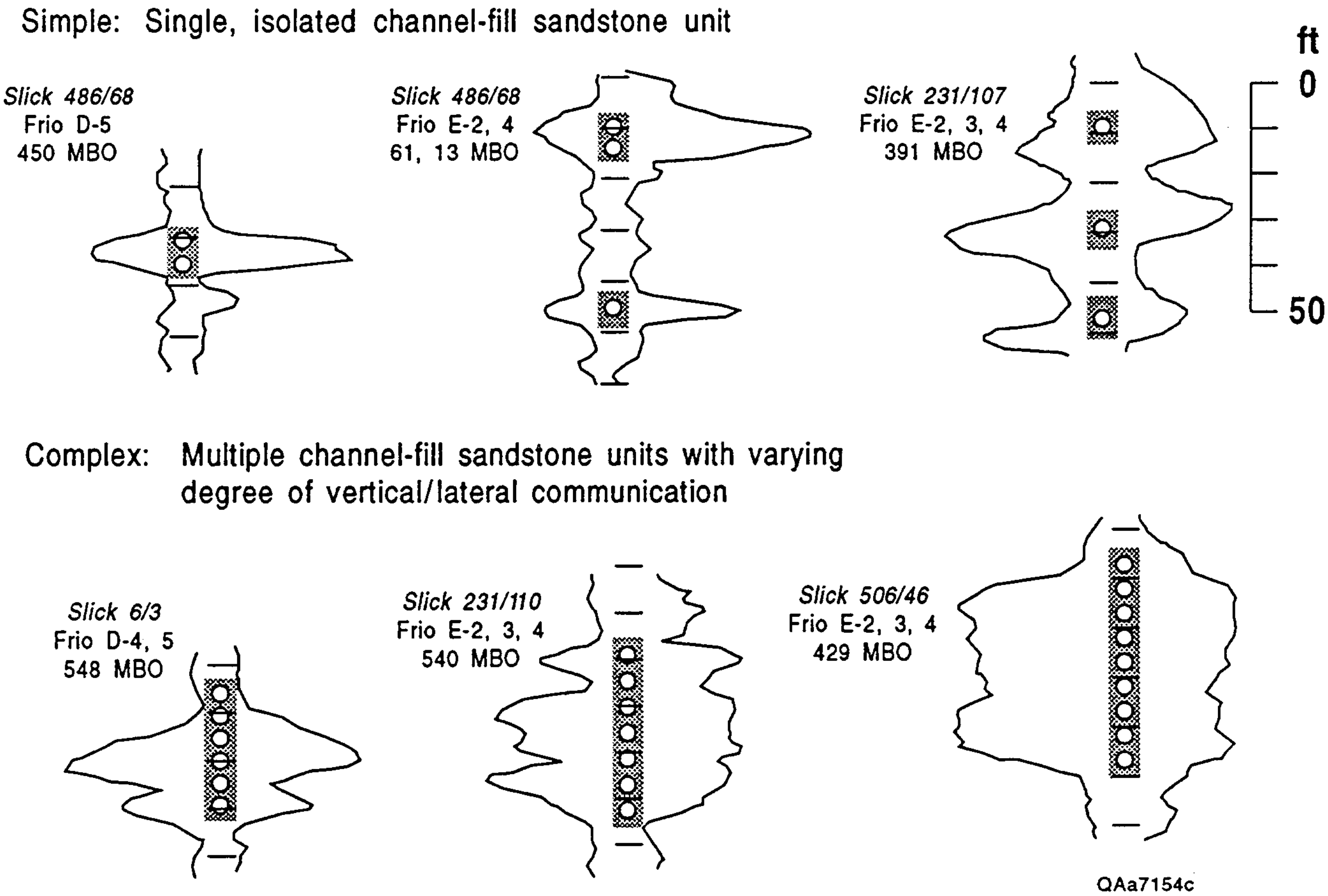

Figure 21. Rincon reservoir sandstones range from single, isolated channel-fill units (1) to more complex zones consisting of multiple stacked channel-fill sandstones (2). These complex units are common and have significant potential for containing incompletely drained and untapped reservoir compartments.

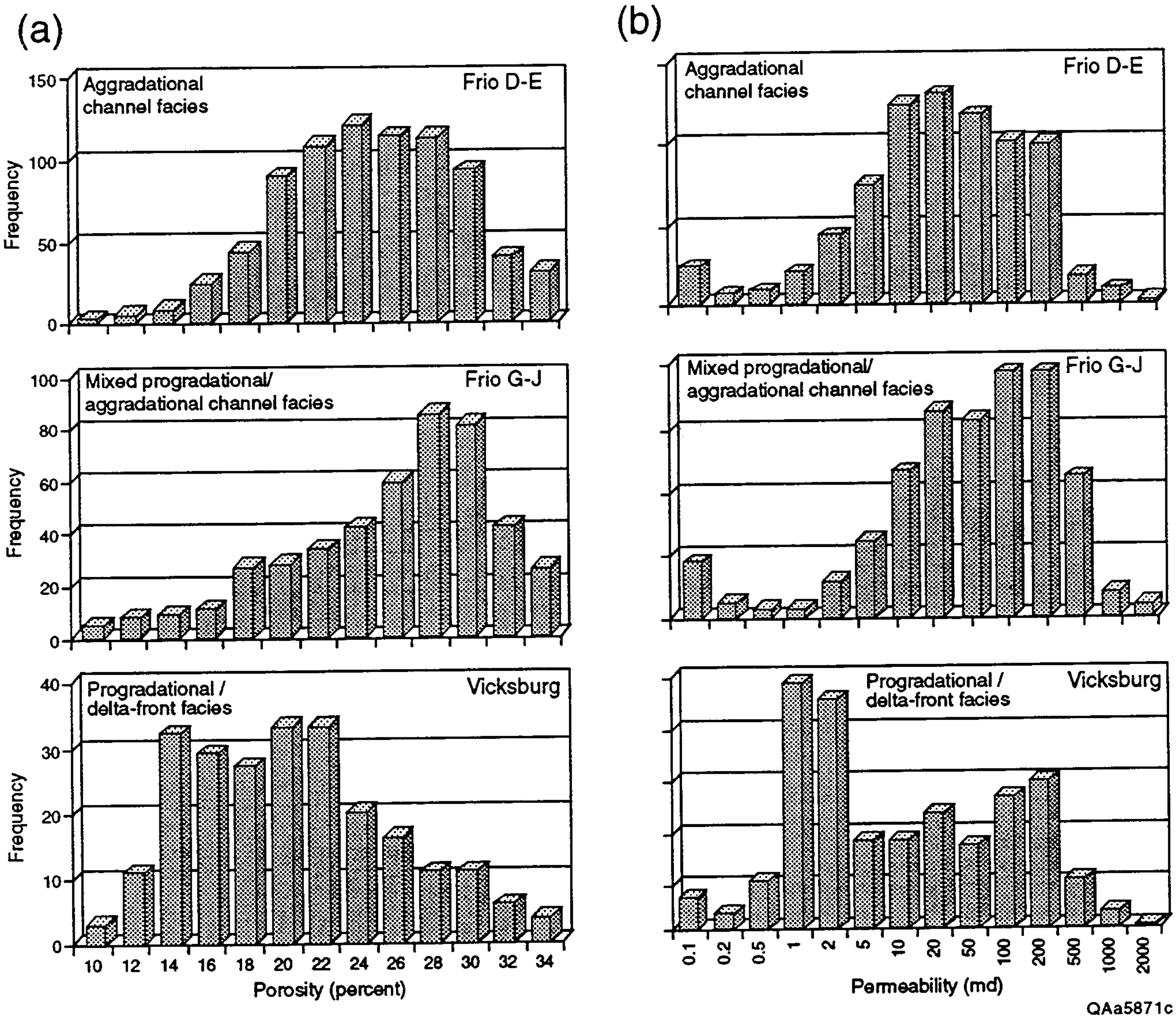

Figure 22. Histograms showing frequency distributions for values of core porosity and permeability from various fluvial-deltaic reservoir groups within the productive Frio-Vicksburg stratigraphic interval.

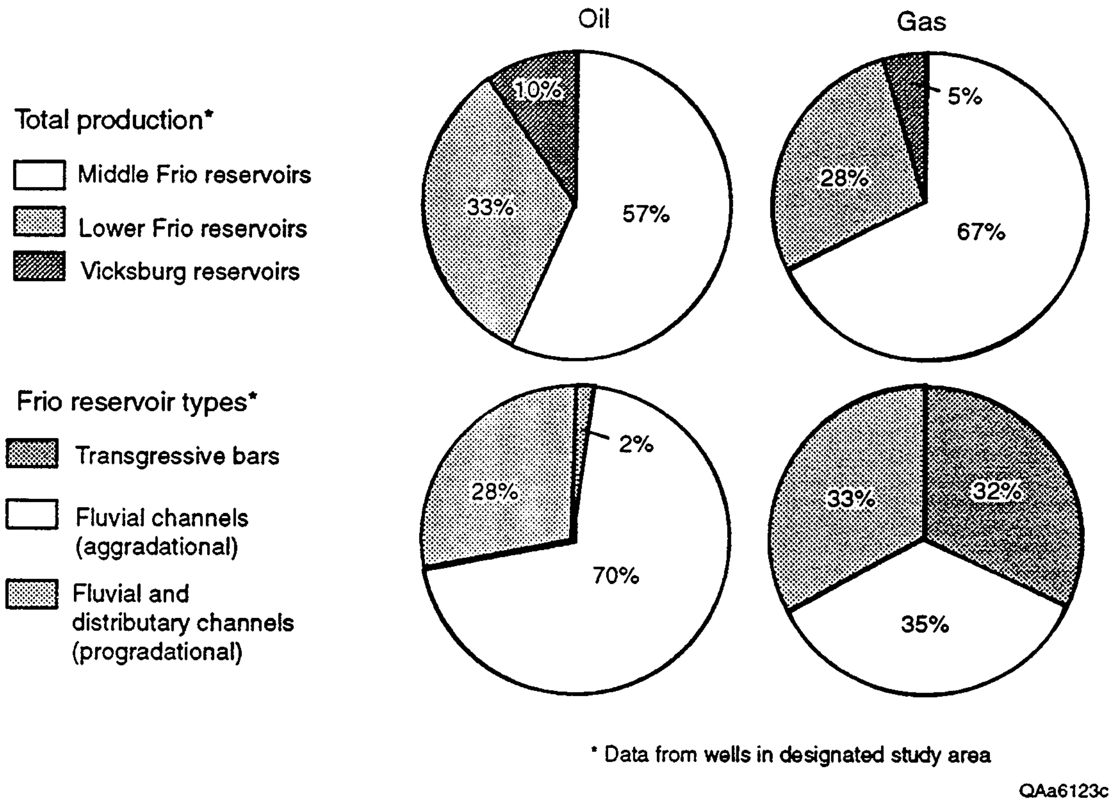

Figure 23. Stratigraphic distribution of oil and gas production in middle Frio, lower Frio, and upper Vicksburg reservoir zones within Rincon field. Frio reservoir zones have been classified as belonging to progradational, aggradational, or retrogradational (transgressive) cycles of deposition. Aggradational channel sandstones contain the majority of the oil resource, and the retrogradational units are almost exclusively gas reservoirs.

(mean ϕ = 27.1 percent, median k = 85 md) than their counterparts in the aggradational middle Frio (mean ϕ = 25.7 percent, median k = 38 md). In addition, the porosity and permeability values of middle Frio reservoirs appear normally distributed, whereas the distribution of values in lower Frio units is positively skewed. Different frequency distributions for reservoir attributes have been documented to have important implications in estimates of recovery efficiency when average values of non-normally distributed data are used to calculate reservoir volumes (Holtz and others, 1994).

Core porosity and permeability values were crossplotted to identify variability within individual Frio reservoir zones. Examples of these data from a middle Frio aggradational channel sandstone (Frio E), a transgressive bar sandstone (Frio F), and a lower Frio mixed aggradational channel sandstone (Frio G) are shown in Figure 24. Core data measured from sands in Frio E and Frio G dip-oriented channel oil reservoirs exhibit a greater range of values than the Frio F gas reservoir. This most likely reflects the greater variability of depositional facies present within the fluvially dominated reservoir zones and may also be partly an artifact of slightly higher textural maturity of the reworked bar sandstone units. The lower Frio G sandstone unit also exhibits greater variability and a weaker relationship between porosity and permeability than the Frio E sandstone unit, its channel counterpart in the middle Frio interval.

Implications of Reservoir Stratigraphy on Hydrocarbon Production and Reservoir Heterogeneity

Subdivisions within main Frio reservoir producing zones are illustrated in the log in Figure 25, along with cumulative oil and gas production for each zone and the relative position of each reservoir within a genetic stratigraphic stacking hierarchy developed for the Rincon field section. Low-resistivity shale markers separate the primary reservoir sandstone zones, and two significant low-resistivity markers interpreted to represent maximum flooding surfaces have been identified at the top of a transgressive bar sandstone complex (B and F units). The F shale marker is interpreted to represent 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 characteristic of Frio G–J sandstone units to purely aggradational sand deposition typical of Frio C, D, and E sandstone zones.

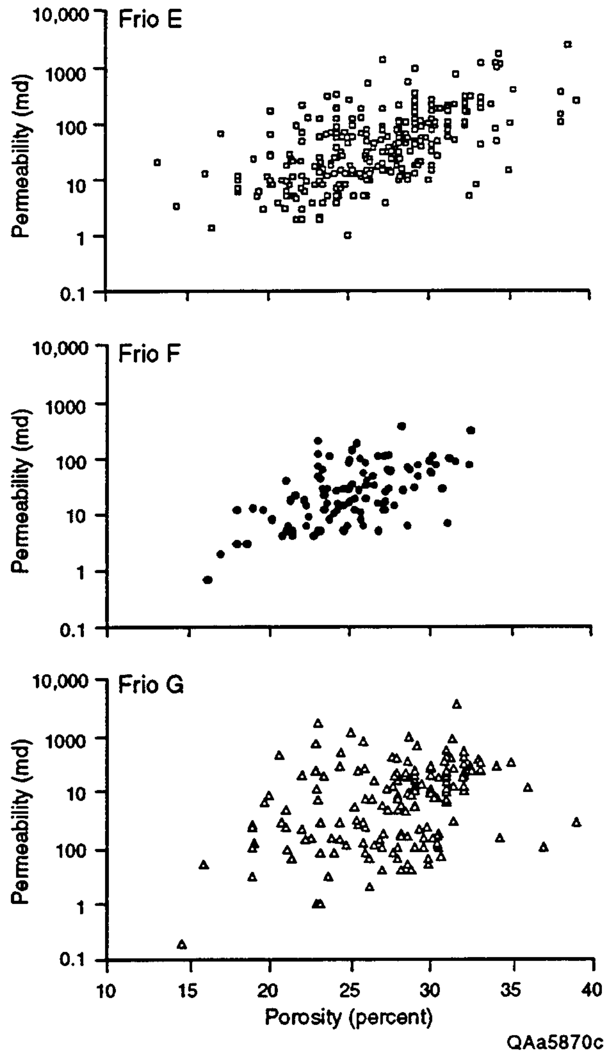

Figure 24. Crossplots of porosity and permeability values measured from wireline cores in representative Frio reservoirs in Rincon field. Dip-elongate channel sandstone oil reservoirs from the E and G units represent deposition in middle and lower Frio intervals, respectively. The F unit is a strike-elongate transgressive unit that exhibits significantly less variability in porosity and permeability values than the E and G channel reservoir facies above and below.

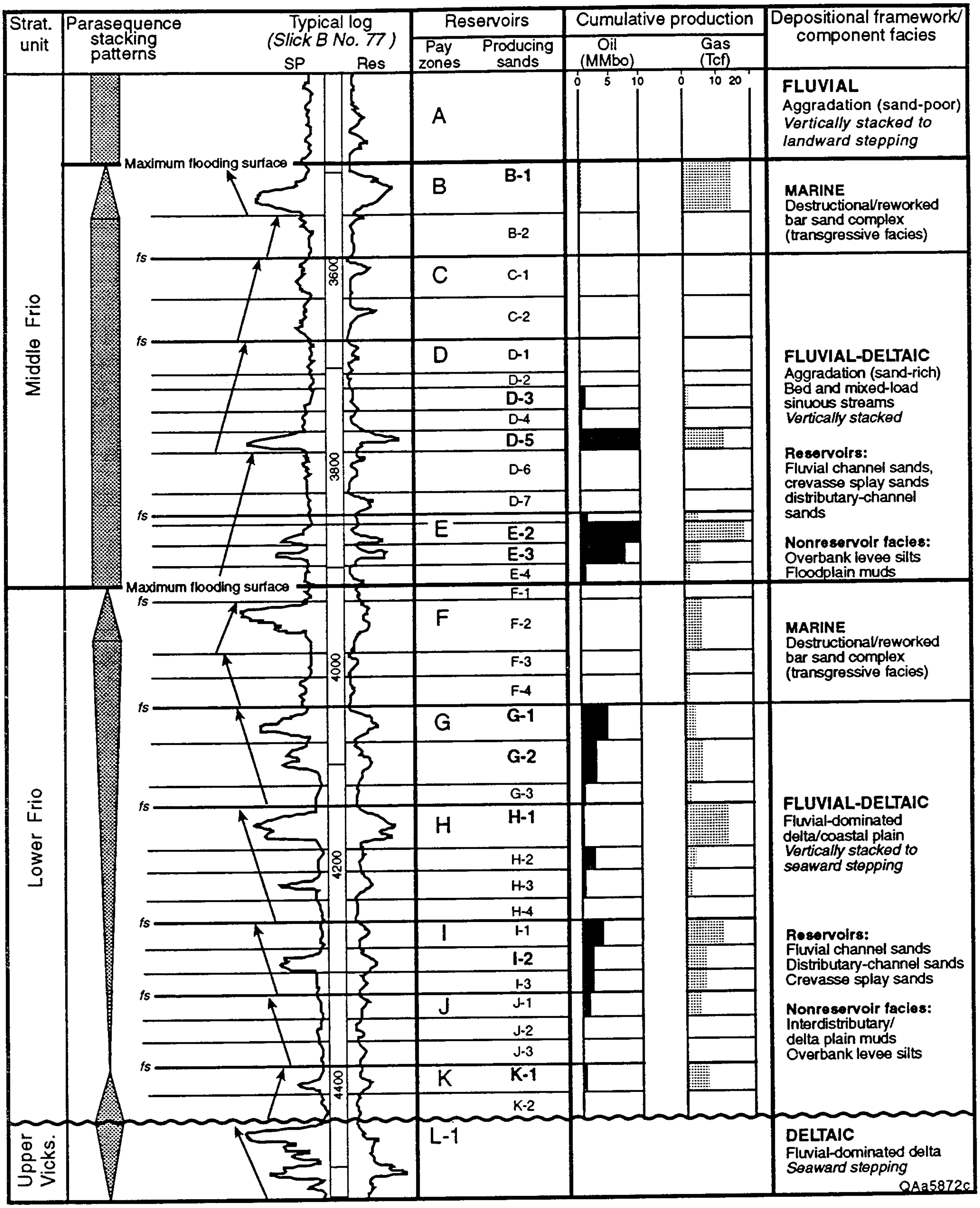

Figure 25. Expanded type log from Rincon field of lower and middle Frio reservoirs illustrating reservoir nomenclature of individual producing units and the stratigraphic distribution of oil and gas production.

Each transgressive sandstone complex that occurs below a major flooding surface (Frio B and F units) produces mostly gas and is not an important oil reservoir. The aggradational channel sandstones (e.g., Frio D, E, and G units) located below each transgressive unit are primarily oil reservoirs, with the most significant accumulations occurring in the sandstones immediately below the main gas reservoir. This observation suggests that these flooding surfaces may act as important subregional seals.

Specific reservoir data for each of the three genetic stacking intervals identified in the productive reservoir section in Rincon field are presented in Figure 26. Reservoir attributes for each zone (mean porosity, permeability, net sandstone thickness, and percent sandstone) are compared with production history (gas/oil ratio, cumulative oil produced, percentage of total production) and current development status (percentage of completions abandoned) in order to identify differences in reservoir attributes (heterogeneity) between zones and to rank incremental reserve growth potential. Several reservoir zones in the study area (C, H, J, K) have already been completely abandoned.

Identification of Reservoirs with High Potential for Incremental Oil Recovery

The Frio D and E sand series are the two most highly prolific reservoir zones in Rincon field. Sandstones within this combined interval have produced more than 22 MMbbl of oil since production began in 1940 (Table 11). The Frio E sandstone consists of four individual sandstone units and has produced nearly 12 MMSTB of oil since production began in 1940. Secondary waterflooding in the Frio E reservoir zone successfully accounted for 2.5 MMSTB of additional production. Using average reservoir values of 26.5% porosity and 37.5% water saturation, Frio E sandstones are estimated to have an overall recovery efficiency of 38%.

The main productive Frio D reservoir zone also consists of four stratigraphic units that have produced nearly 10 MMSTB oil. Frio D sandstones have reservoir attributes resembling those of Frio E reservoirs (average porosity of 25.2%, S_w of 40.5%, and estimated OOIP of approximately 35 MMSTB) but a significantly lower recovery efficiency of 28%. Waterflooding attempts in this reservoir zone accounted for secondary recovery amounting to only 2% of total D production. These disappointing results were attributed by the field operator to the heterogeneous nature of the D sandstone interval.

Zone	Unit	Pay	ϕ (percent)	k (md)	Net (ft)	Percent sand	GOR prod.	Cum Mbo	Percent total oil	Percent aband zones
Aggradational (3100-3500')	B		27.0	63	13	13	85	150	<1	81
	C		na	na	na	na		159	<1	100
	D		25.3	57	21	27	1.7	10.064	16	95
	E		26.6	68	18	22	2.1	15.282	24	85
TOTALS					52			22,639	40	
Mixed aggrad/prograd (3500-4100 ft)	F		24.7	26	25	18	69	416	<1	
	G		27.4	97	18	17	1.9	5,852	9	86
	H		27.9	56	17	na	16.9	7,387	11	100
	I		25.6	31	13	na	5.9	3,700	6	94
	J		24.7	89	16	na	4.7	645	1	100
TOTALS					89			18,000	27	
Progradational (>4200 ft)	K		26.9	63	9	na	51	1,102	2	100
	L							660	1	81
	VK							19.298	30	

Gas reservoir | Oil reservoir | Strike-oriented (bar) sandstone | Dip-elongate (channel) sandstone | Delta front sandstone

- Mean porosity and permeability values based on wireline core analyses
- Reservoir ϕ, k, net, and percent sand from study area wells only (see location map)
- Percent abandoned zones calculated from total completions and remaining active (producing and shut-in) zones as of 1991.
- Values listed as na reflects limited data available

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Figure 26. Summary of reservoir stratigraphic framework, primary depositional facies, pay type, petrophysical attributes, and production history for Frio reservoir zones in Rincon field.

Table 11: Summary of reservoir data for the Frio D and E zones in Rincon field.

	Frio D Sandstone	Frio E Sandstone
CURRENT STATUS:	95% of completions abandoned	85% of completions abandoned
DEPTH INTERVAL:	3700-3800 ft	3800-3900 ft
RESERVOIR UNITS AND GEOMETRY:	D-3, 4, 5, 6 zones fluvial channel system with dip-oriented geometry	E-1, 2, 3, 4 zones: Fluvial channel system with dip-oriented geometry
PETROPHYSICAL ATTRIBUTES: (wireline core data)		
Mean porosity:	25% (range 21-26%)	26% (range 22-28%)
Geometric mean permeability:	50 md (range 23-91 md)	59 md (range 31-116 md)
Mean Initial water saturation:	40.5%	37.5%
TOTAL PRODUCTION (1940-1990):	> 9.8 MMBO	>14.0 MMBO
SECONDARY PRODUCTION:	200 MBO from waterflooding (2% total D production)	2.5 MMBO from waterflooding (21% total E production)
ORIGINAL ESTIMATED OOIP:	33.85 MMBO	37.04 MMBO
RECOVERY EFFICIENCY: (Operator data)	29% *(based on 27.5% f, 40.5% S_w)*	38% *(based on 26.5% f, 37.5% S_w)*
ESTIMATED RESIDUAL OIL:		
@ 50% probability:	15.4 MMBO (45% OOIP)	16.0 MMBO (43% OOIP)
@ 95% probability:	20.8 MMBO (61% OOIP)	21.7 MMBO (58% OOIP)
EST. REMAINING MOBILE OIL:		
@ 50% probability:	8.7 MMBO (26% OOIP)	7.0 MMBO (19% OOIP)
@ 95% probability:	3.3 MMBO (10% OOIP)	1.4 MMBO (4% OOIP)

The stratigraphic complexity of this interval of vertically stacked and laterally coalescing sand lobes provides ideal conditions for the isolation of oil accumulations in multiple reservoir compartments, many of which are now incompletely drained or completely untapped. Significant additional reserves may be identified through integrated geologic and engineering studies that characterize the heterogeneity of the various reservoir facies.

Preliminary Estimates of Remaining Potential in Frio D and E Reservoirs

Preliminary assessment of the probable remaining mobile oil resource in each of these reservoirs was performed by using mean values of acre/ft, porosity, S_w, and B_{oi} specific to each reservoir to calculate an estimate of original oil in place. The playwide probability distribution of S_o

values was then used to generate a range of possible residual oil values (Figure 27). Cumulative production was subtracted from this residual oil distribution to predict the range of the remaining mobile oil resource that may be present in these reservoirs. The mean results of this simulation (at 50% probability) shown in Figure 28 suggest that more than 15 MMBO of additional recoverable mobile oil may be present in Frio D and E reservoirs (Table 11). A more conservative estimate at the 95% probability level indicates that nearly 5 MMBO of mobile oil is remaining. At least 10% of the volume of original oil in place for the stratigraphically heterogeneous Frio D sandstone zone, or more than 3.3 MBO, is expected to be present as remaining mobile oil. This significant remaining oil resource is the target of our further delineation studies in Rincon field.

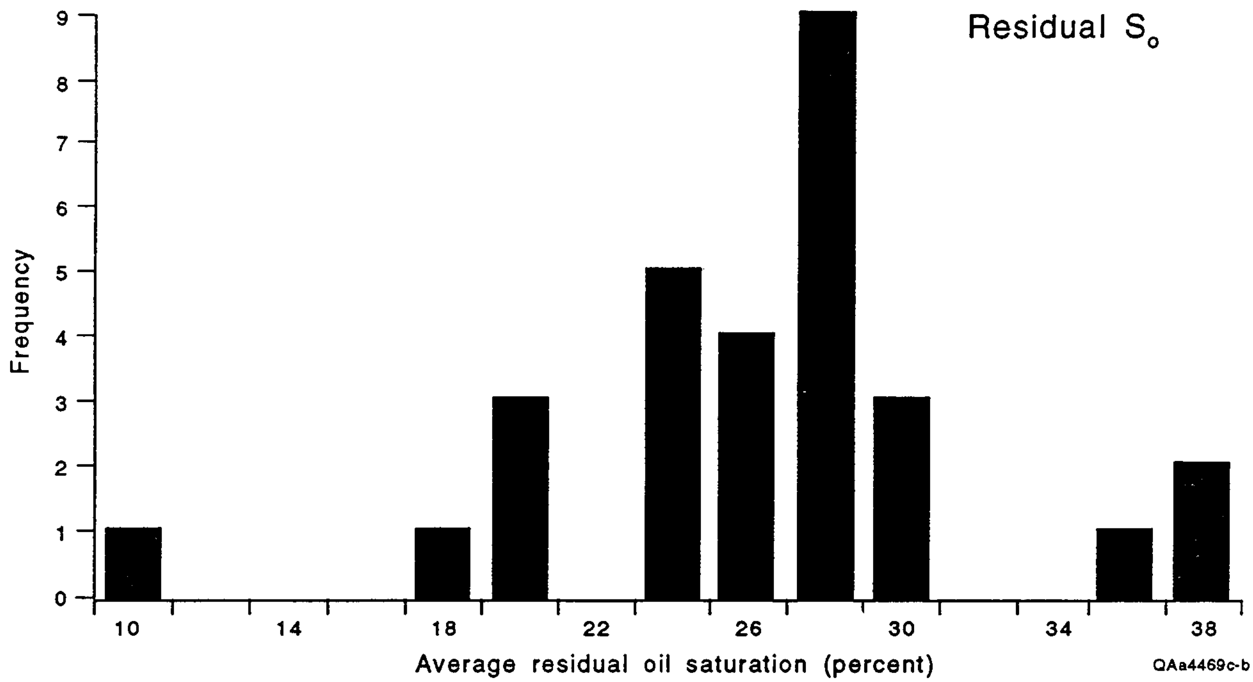
Characterization of Reservoir Heterogeneity

Identification of additional oil resources in Frio D and E reservoir sandstones is being pursued through the evaluation of existing oil production trends, facies mapping, and analysis of abundant petrophysical data from wireline cores and geophysical logs. Detailed mapping of the internal physical architecture of individual reservoir flow units should explain why these reservoir zones have produced differently and may identify the location of untapped and incompletely drained reservoir compartments that may have significant potential for additional oil recovery. Delineation of additional oil resources in two Frio reservoir zones in Rincon field will be completed by integrating reservoir mapping with the development of petrophysical models based on core and geophysical log data (Table 12).

Whole Core Studies

Methods

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 (Table 13). Core descriptions from both wells, along with porosity and permeability profiles derived from conventional core analysis data, are illustrated in Figures 29, 30, and 31. Unfortunately, the quality of the SP log for well A133 is very poor, and there is no SP log for well



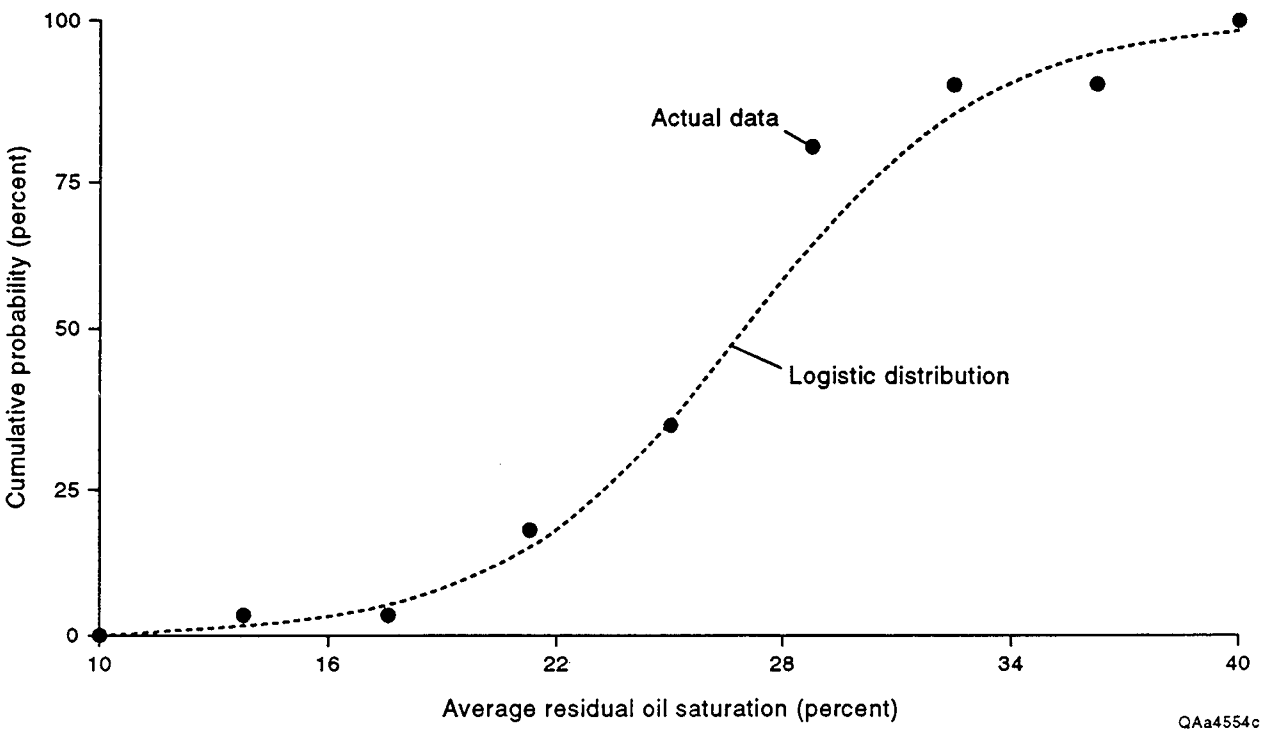


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Figure 27. (A) Histogram illustrating distributions for values of reservoir residual oil saturation throughout the play with (B) Cumulative probability distribution curves comparing actual reservoir residual oil saturation with a logistic function fit. Cumulative probability distribution comparing actual simulation results of residual oil with a best-fit beta function model.

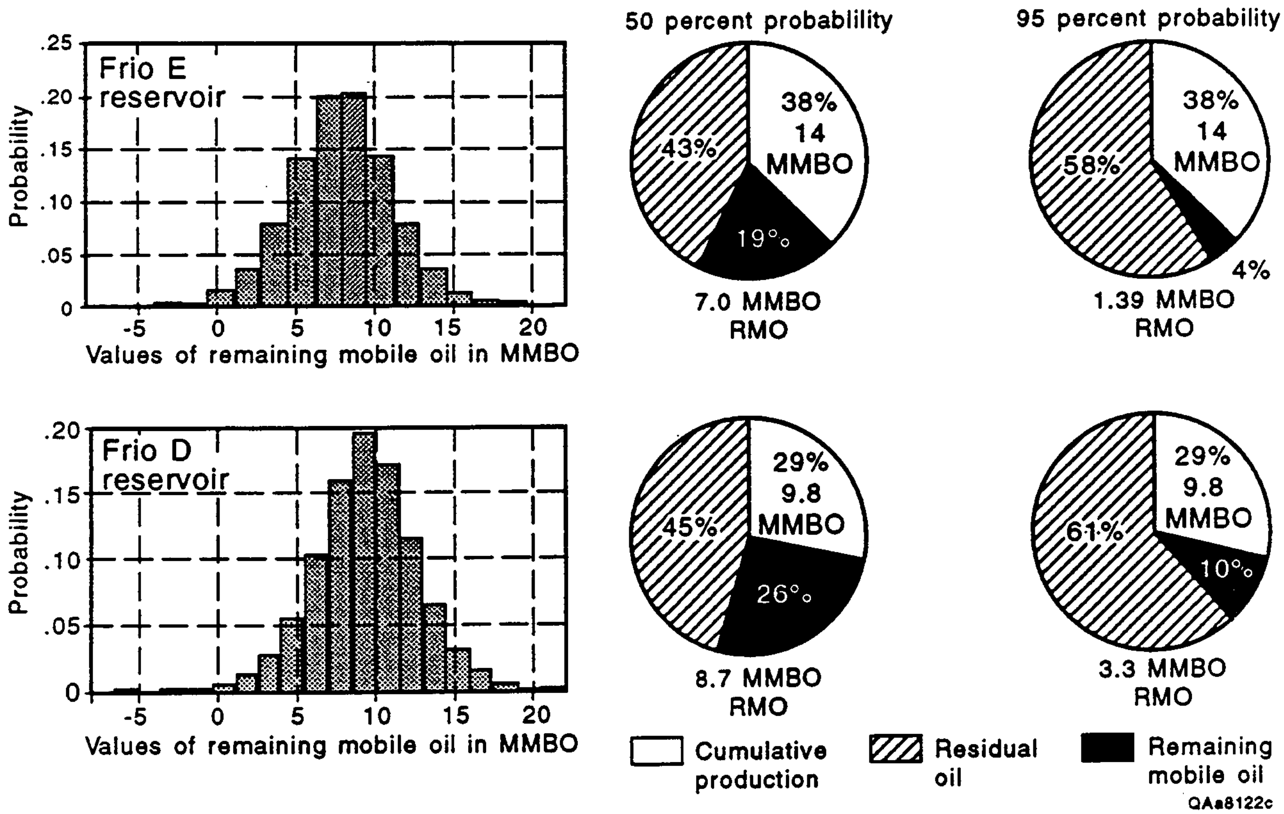


Figure 28. Mean (50% probability) and conservative estimates (95% probability) of remaining mobile oil present in Frio E reservoir sandstones in Rincon field. Mean (50% probability) and conservative estimates (95% probability) of remaining mobile oil present in Frio D reservoir sandstones in Rincon field. The highly heterogeneous Frio D sandstone zone has recovered nearly 10 MMBO to date, but has potential for recovering over 3 MMBO of additional oil that is presently residing in untapped and incompletely drained compartments.

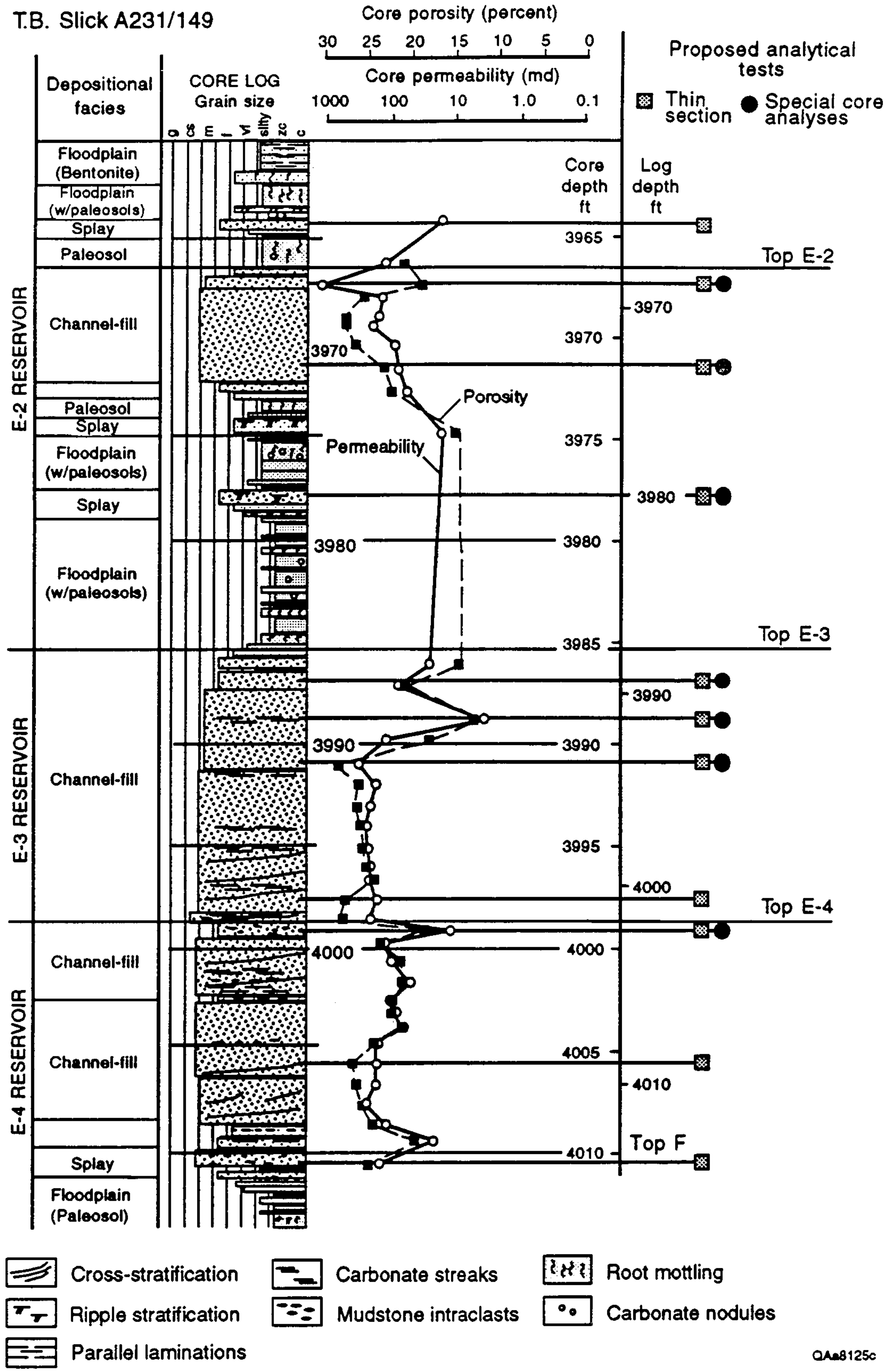


Figure 29. Graphic core log for the T.B. Slick 231:149 well over the Frio E reservoir zone, along with corresponding faices interpretations, core analysis data for porosity and permeability, and location of samples selected for petrographic and special core analyses.

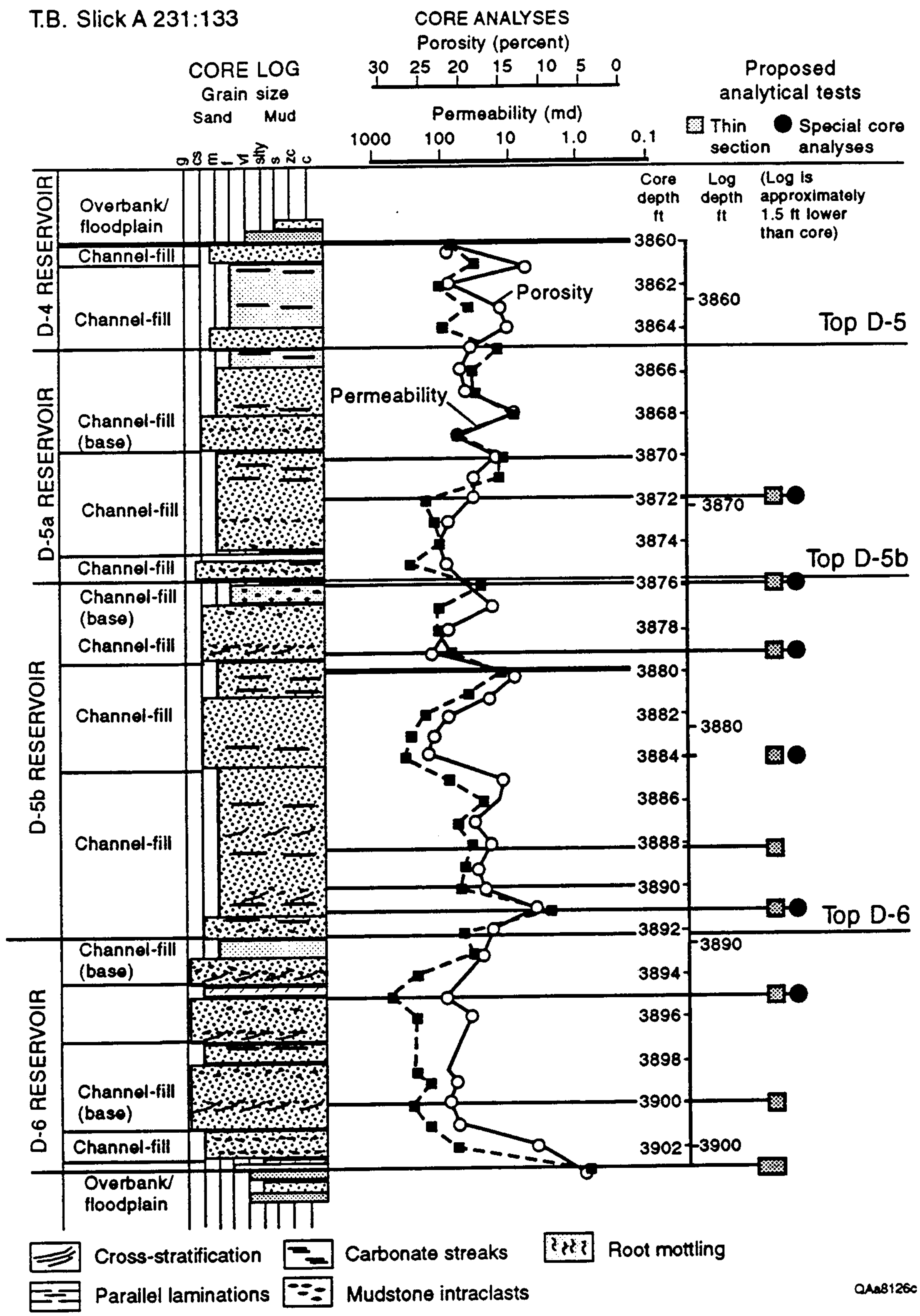


Figure 30. Graphic core log for the T.B. Slick 231:133 well over the Frio D reservoir zone, along with corresponding faices interpretations, core analysis data for porosity and permeability, and location of samples selected for petrographic and special core analyses.

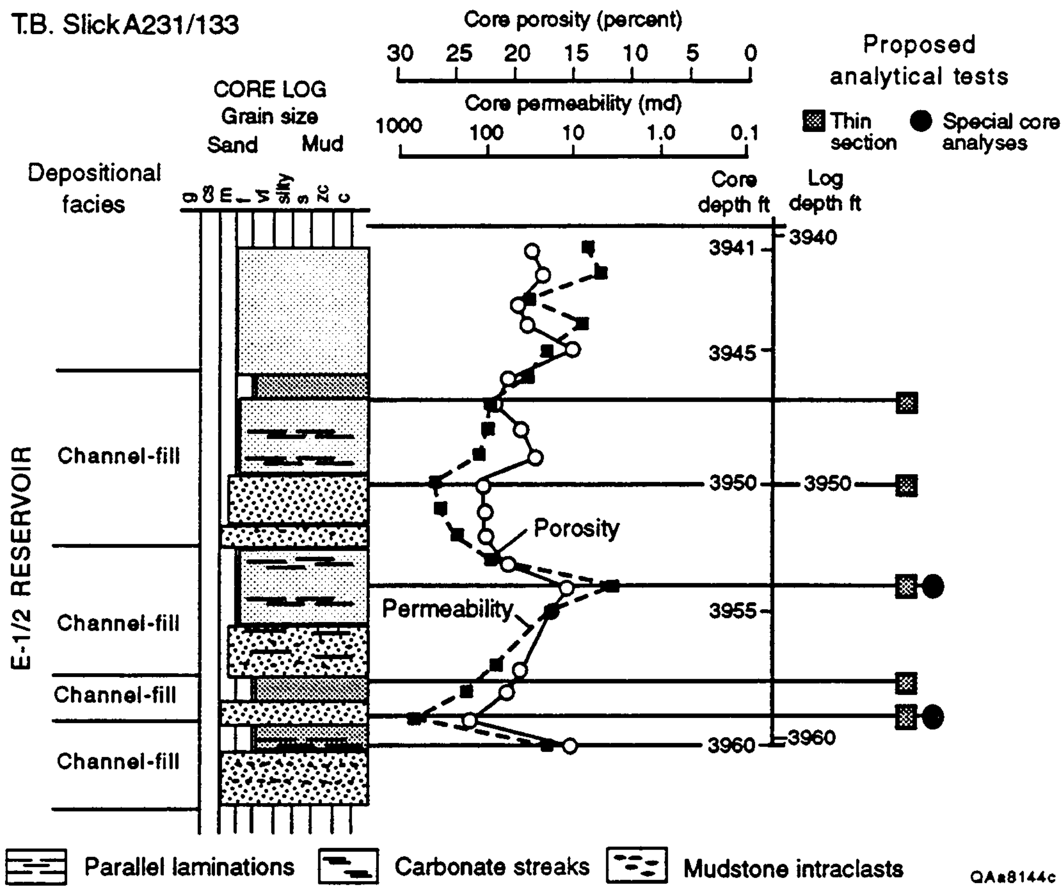


Figure 31. Graphic core log for the T.B. Slick 231:133 well over the Frio E reservoir zone, along with corresponding faices interpretations, core analysis data for porosity and permeability, and location of samples selected for petrographic and special core analyses.

A149. Because the vast majority of log data available from wells in the study area are pre-1950 electric logs (SP, resistivity curves only), it was an original objective of this study to be able to calibrate core facies observed in these two wells to SP log response. Because of the lack of SP log data in both these wells, this was not possible. Core studies therefore focused on detailed description, identification of depositional facies, and sampling for petrographic study and special core analysis. The core preserved from well 133 was not continuous and consisted of individual 1- to 6-inch-long pieces of slabbed 4-inch-diameter core each representing 1-ft core interval. Based on core description information, these pieces are assumed to be representative of the lithology of the entire 1-ft interval. Locations of samples selected for these additional studies are annotated on the core graphic logs shown in Figures 29, 30, and 31.

Table 12: Key goals and methodologies associated with reservoir-scale characterization studies.

Reservoir-scale reservoir characterization
Goals:
• Identify specific locations of unproduced recoverable oil.
• Evaluate how different reservoir architectural styles may directly impact recovery efficiency.
• Develop interwell-scale models of flow unit architecture so results may be applied to other reservoirs, other fields, and other plays in analogous settings.
Methodology:
• Map and compare distribution of trends in oil production, log facies, net sandstone thickness, and reservoir petrophysical attributes.
• Estimate remaining mobile oil resources.
• Describe 3-dimensional flow-unit architecture.

Core facies

Detailed core description and sampling were limited to the two reservoir zones selected for detailed characterization studies: the Frio D and E sandstones. The core from well 149 includes the stratigraphic interval through most of the E reservoir zone (Figure 29), and the well 133 core represents the depth interval through the D reservoir and the top portion of the E reservoir (Figures 30 and 31). 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.

TABLE 13: Summary of conventional core studied.

WELL:	231/149	231/133
Core thickness (total):	70 ft	85 ft interval
Core condition:	continuous interval 4" diameter	1-6" pieces from each 1 ft, 4" diameter slab
Reservoir zones represented in core:	2 (E and G zones)	3 (D, E, and G zones)
Number of sand units per reservoir zone:	E zone (3 sands) G zone (2 sands)	D zone (3 to 4 sands) E zone (1 to 2 sands) G zone (2 sands)
Thin section samples:	E zone (12)	D zone (9) E zone (5)
Special core analyses samples:	E zone (7)	D zone (6) E zone (2)

Depositional facies identified in core are shown on the corresponding graphic logs in Figures 29, 30, and 31. 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. Individual channel-fill sandstones range from 5 to 12 ft thick, whereas splay sandstones were less than 1 ft thick (e.g., 3964 ft, 3974 ft, 3980 ft, Figure 29). Channel-fill sandstones all exhibit upward fining textures, but the thinner splay sandstones appear more uniform or slightly upward coarsening in grain size. 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. These fine-grained units were observed in three intervals within the E reservoir zone in core from well 149 (above 3966 ft, between 3973 and 3984 ft, and below 4013 ft in Figure 29) and were commonly interbedded with splay sandstone units. Some floodplain mudstones are green-gray and possess a mottled waxy texture typical of an altered bentonite (e.g., 3960–3961 ft, Figure 29).

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 others, 1992; Grigsby and Kerr, 1993).

In addition to these three primary facies types, three subfacies—basal, middle, and upper channel-fill facies—were 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 sand), and may include a gravel lag consisting of intraformational clasts of mudstone and calcareous nodules (e.g., 3997 ft, 4010 ft, Figure 29; 3875 ft, 3894 ft, Figure 30). The thickness of the basal facies of the channel-fill is typically less than one foot. 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 unobservable 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 sand to silty sand), 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 the identification of different petrophysical rock types present in the various depositional facies (Figure 32). 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., 3997 ft, 4009 ft, Figure 29; 3876 ft, 3891 ft, Figure 30). Porosity and permeability systematically increase upward through the middle portions of the sand unit and then are typically reduced near the top of a sand where there is a reduction in grain size (e.g., 3970 ft to 3967 ft, 4009 ft to 4003 ft, Figure 29; 3876 ft to 3870 ft, Figure 30). 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., 3964 ft, 3974 ft, Figure 29).

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., 3997 ft,

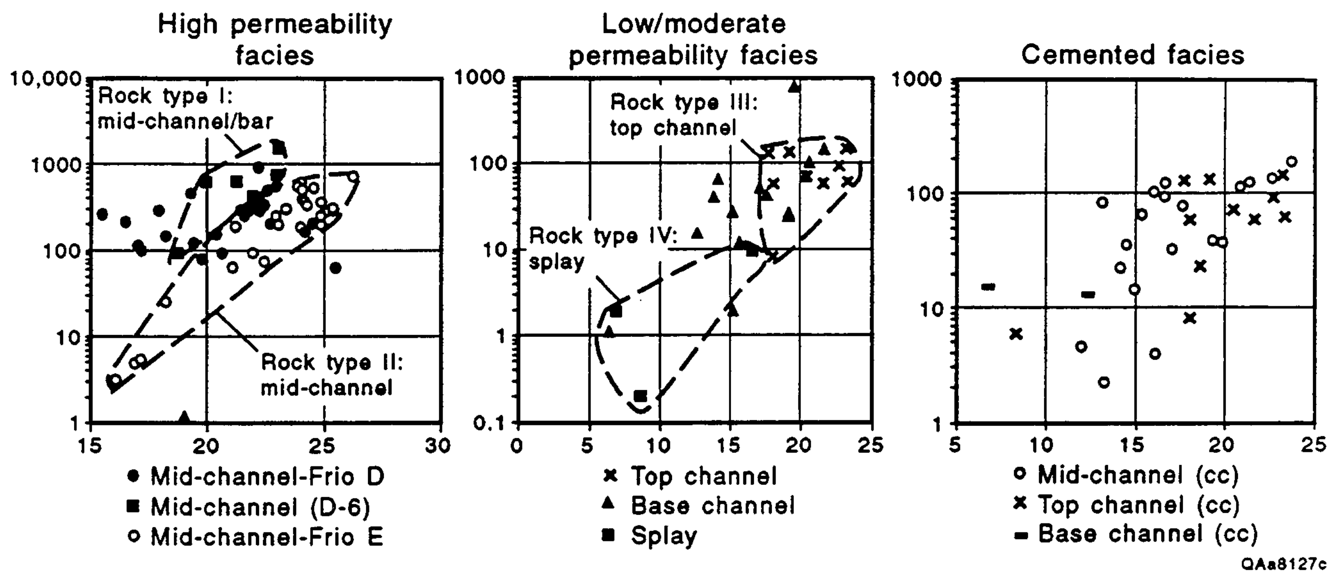


Figure 32. Preliminary petrophysical rock types identified from whole core studies include high permeability channel (I) and bar (II) facies, and low to moderate permeability channel (III), splay (IV), and carbonate cemented channel facies.

Figure 29; 3875 ft, Figure 30). Whether this permeability reduction is great enough or laterally persistent enough to create a partial or even complete barrier to flow between the two sandstone units will be addressed in our detailed mapping and cross-section correlation efforts. Another rock type that has not been designated a separate facies consists of middle or upper channel facies sandstones that contain 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., 3989 ft, Figure 29; 3871 ft, Figure 30).

Petrography

Twenty-two samples from core in both wells that represent the various reservoir facies and petrophysical rock types were chosen for petrographic study (Figures 29, 30, and 31). Samples have been selected to provide good data coverage over each of the various reservoir facies and rock types present in both wells. These include base, middle, and tops of channel-fill sandstones and splay facies sandstones. The goal of the petrographic work is to identify the type and possible variations in pore geometry in these sandstones and, in addition, to provide information on cement types and the degree to which diagenesis controls reservoir quality.

Special core analyses

Objectives

One of the main research efforts in this project is the delineation of remaining mobile oil. To achieve this goal, an accurate understanding of original oil in place and residual oil saturation is needed. For this, it is necessary to use reasonable estimates of irreducible water saturation or residual oil saturation in these reservoirs. Our petrophysical modeling efforts in these reservoirs will be significantly compromised by the lack of modern log data in these wells because we are forced to rely on porosity-permeability relationships derived solely from old electric logs. The quality of whole core we have from these two wells provides us with an excellent opportunity to perform special core analyses on selected reservoir intervals and to obtain measurements of these attributes critical to our delineation of oil in place and remaining mobile oil.

Samples for special core analyses have been selected in the continuous core of the E reservoir in well 149 (Figure 29) that represent the range of petrophysical rock types identified from core description and porosity and permeability data from conventional core analysis (Figure 32). Samples were chosen to demonstrate differences (if any) in measured values (1) between the base and top of a single-story sandstone unit, (2) between the base and top of a multistoried/stacked channel unit, and (3) in a thin crevasse splay sandstone. We have also selected channel base/top pairs in the core from well 133, three in the Frio D and two in the E sandstone (Figures 30 and 31). Samples from this well will provide our only rock data from the D sandstone, and the results from the E sandstone in well 133 will provide comparison from results in the same E reservoir zone measured in well 149. Petrographic thin sections were prepared from all plugs selected for special core analyses.

Test results will be incorporated in the petrophysical modeling and resource assessments. A brief summary of the special core measurements being conducted and the application of results to this study is provided below.

Capillary pressure

Mercury-injection capillary pressure measurements are being performed on 15 samples. The primary objective of these tests is 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 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 Sw_{irr} will in turn be used in subsequent resource calculations. Capillary pressure results may also be used to estimate reservoir efficiency.

Formation resistivity

Formation resistivity measurements are being 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 S_w in these Frio reservoir rock types.

Core flood and relative permeability

Core flood tests are being conducted on 15 core plugs to acquire data on residual oil saturation (S_{or}) and end point relative permeability. We have no 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% (Figure 29). S_{or} data are obviously critical to obtaining reasonable estimates of remaining mobile oil.

Relative permeability is defined as the ratio of effective permeability of a fluid to the absolute permeability of the rock and therefore is directly dependent on saturation (Honarpour and Mahmood, 1988). Relative permeability is very closely related to pore size distributions (Archie, 1942), and the results from relative permeability measurements conducted on the cores will be compared to the distribution of pore sizes determined from capillary pressure measurements to provide a check on the validity of those results.

Petrophysical Studies and Characterization of Reservoir Facies

Objectives

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 6 wells have porosity logs) requires our petrophysical characterization of porosity to be based primarily on indirect methods using nonporosity logs such as SP and resistivity.

Present status and future strategies for fieldwide formation evaluation studies

Petrophysical reservoir studies are still in progress and are scheduled for completion at the end of calendar year 1994. Calculation of shale volumes, net sand thicknesses, and percentage sand values have been completed and results have been incorporated into mapping of individual reservoir subunits. Core data from both whole core studies and existing wireline core analyses have been evaluated in detail. Core porosity and permeability data have been integrated with reservoir mapping studies to characterize petrophysical reservoir attributes for various depositional facies and to identify differences among lithofacies types. Two distinctly different porosity-permeability relationships were identified.

Porosity-resistivity relationships are currently being derived for six wells in the study area that have porosity log data. These results will be compared to investigations of porosity-resistivity relationships in wells where porosity information is only available in the form of wireline core analysis data. After identification of petrophysical relationships are completed for wells with core data, a porosity-resistivity model will be developed and applied to the derivation of porosity in remaining wells in the study area that have only electric log data.

Calculation of shale volumes

The model used to calculate V_{sh} was based on SP log data because there are very few wells with gamma ray logs in the field. The SP index of shale volume (I_{SP}) is defined as:

$$I_{SP} = \frac{SP - SP_{min}}{SP_{max} - SP_{min}} \qquad (1)$$

where SP is the log value for a given depth, SP_{min} is the log value determined for clean sandstone, and SP_{max} is the SP log value designated as the shale baseline. Before calculating shale volumes, all logs were depth adjusted to corresponding core data, if available. After an appropriate shale baseline was identified for the reservoir interval in question, all logs were normalized to a standard shale baseline. This facilitated calculations in log intervals where the shale baseline was shifted.

Calculation of net sandstone and percentage sandstone values

Net sandstone thicknesses were determined using cutoff values of V_{sh}. The relationship between V_{sh} and net sandstone thickness was based on the standard Gulf Coast model that uses a 67% cutoff value. Visual inspection of available conventional core from two wells in Rincon Field confirms that this assumption is reasonable. Values of net sandstone and percentage sandstone derived from these calculations were used in reservoir mapping.

Reservoir mapping and facies studies

A series of maps were constructed on each of the Frio D and Frio E reservoir subunits using (1) net sandstone values based on shale volume calculations from resistivity logs for each well and (2) depositional facies interpreted from electric log signature. Percentage sandstone maps were also constructed. Evaluation of net sandstone thickness patterns and facies distributions for each subunit reveals a systematic progression of depositional setting and reservoir geometry from the base of the Frio E reservoir through the top of the productive Frio D zone.

Frio E reservoir unit map patterns

The Frio E reservoir zone consists of strata from the F shale marker to the E shale marker (Figure 33). The entire zone is composed of four predominantly upward-fining units divided by three low-resistivity shale markers. Each unit between two shale markers represents a depositional parasequence that together make up a larger scale, back-stepping, retrogradational cycle that takes 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 (Figure 34). 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 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 (Figure 34). 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 connected, suggesting some flow communication would be present between the two.

Higher up section in the E-2 unit, dip-oriented channel geometries still predominate (Figure 34). In the updip portions of these channels, there are some small features in which sandstone patterns are strike oriented. A significant change in the amount and distribution of sandstone is observed in the E-1 unit, the uppermost depositional interval of the Frio E zone (Figure 34). Floodplain facies predominate, and the majority of sandstone is distributed in strike-oriented bodies that are limited in areal extent. A narrow dip-elongate channel system is present in the far southwestern corner (bottom left) of the map area. These bar-shaped sandstone bodies are interpreted to represent earlier deposited E zone channel facies that have been reworked by retrogradational processes associated with the advance of a laterally extensive flooding surface that is located at the top of the E zone.

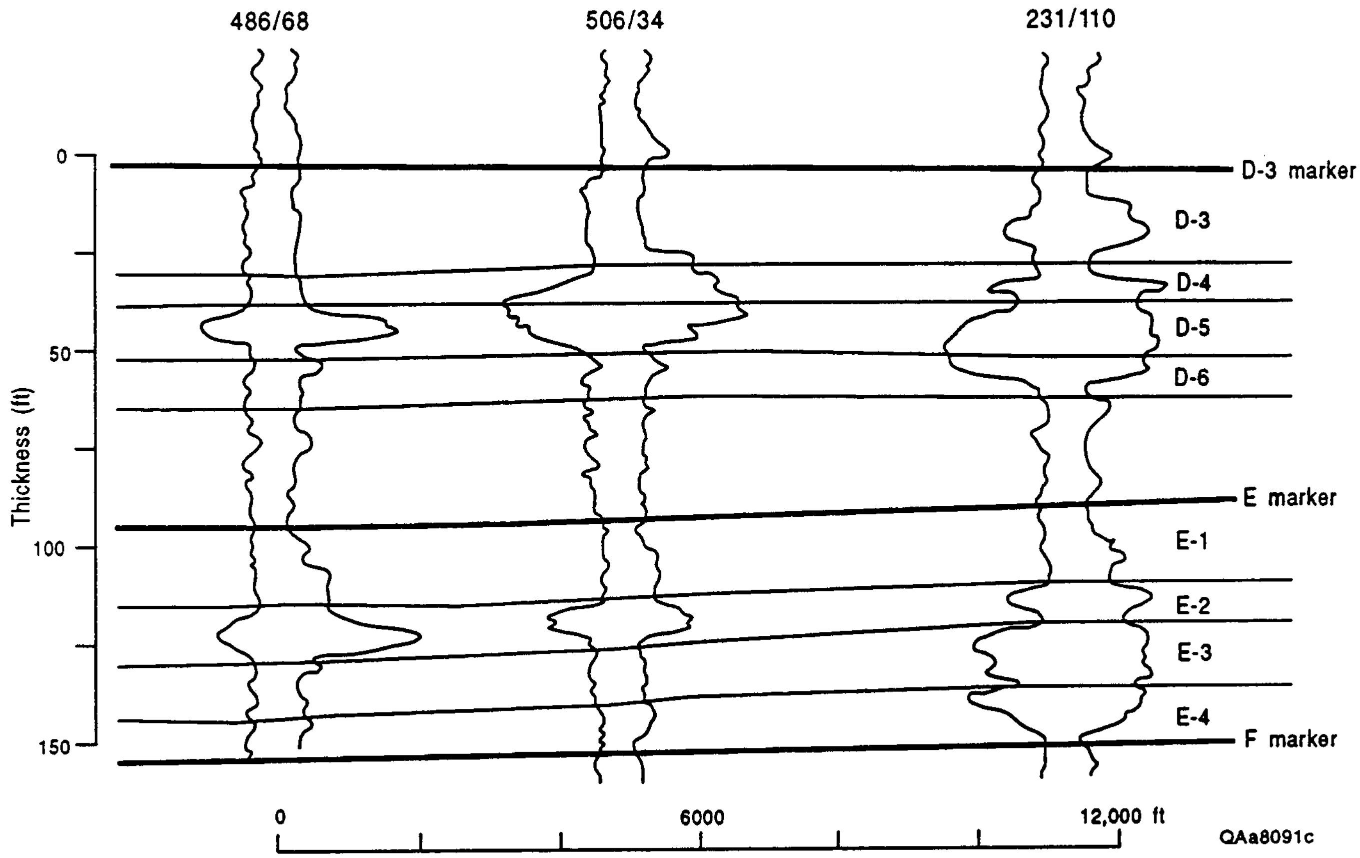


Figure 33. Log profiles in three representative wells illustrating along-strike variability and nomenclature associated with reservoir subunits of the Frio D and E reservoir zones in Rincon field.

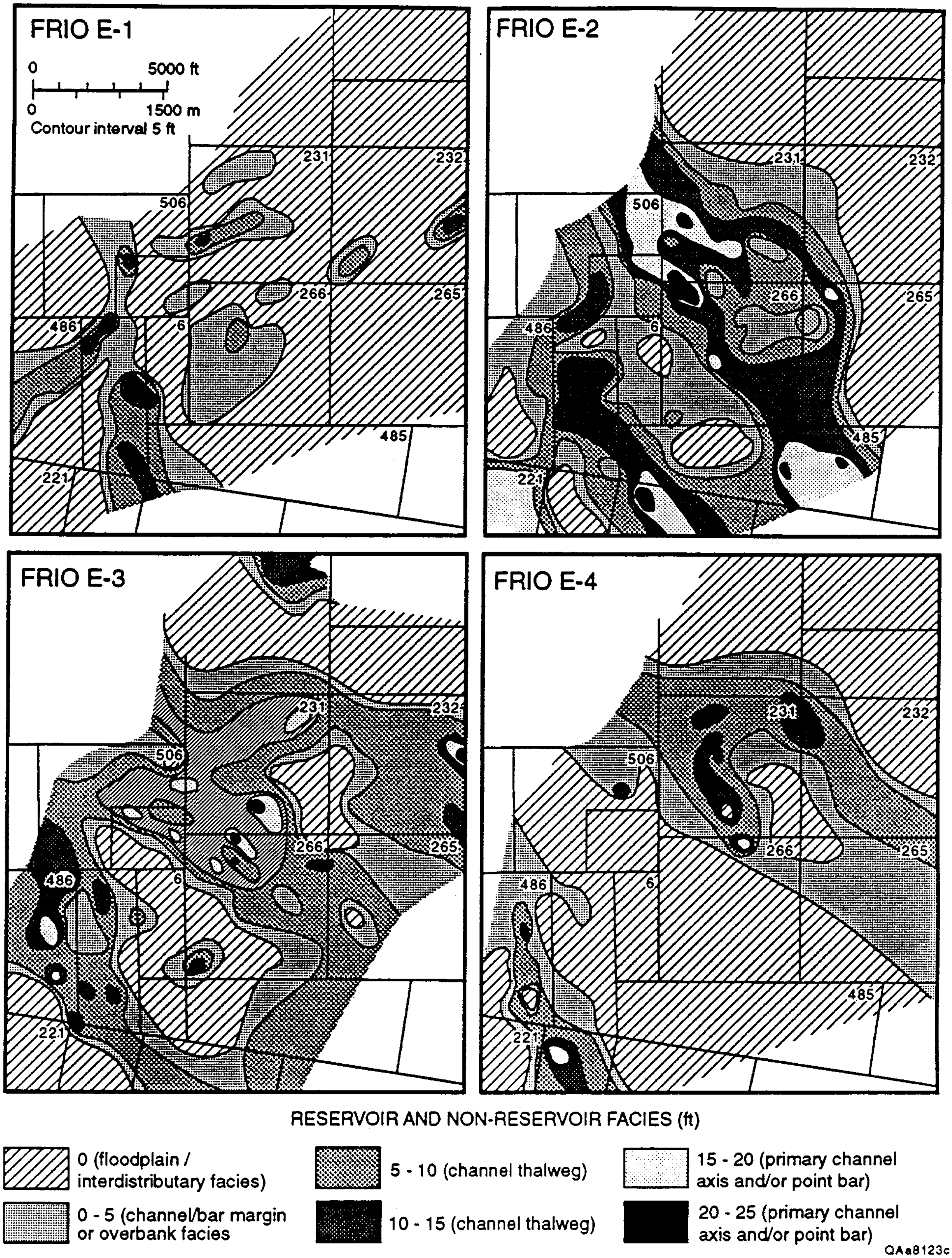


Figure 34. Series of net sandstone isopach and facies maps showing changes in the distribution of facies and sandstone facies geometry for the Frio E-4, E-3, E-2, and E-1 reservoir units.

Frio D reservoir unit map patterns

The Frio D reservoir zone consists of strata from the top of the E-1 shale marker to the D-3 shale marker (Figure 33). Similar to the E reservoir zone, the productive D reservoir interval consists of four discrete depositional parasequences divided by three low-resistivity shale markers. 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 progradational and aggradational units. The complex association of D reservoir facies and units provides ideal conditions for isolation of oil accumulations in multiple reservoir compartments.

Located above the E marker flooding surface, the D-6 unit is the lowermost sandstone of the D reservoir zone. Dip-elongate channel deposition appears to be present in the northern portion of the map area (Figure 35), suggesting that primary sediment transport style has changed to one of progradation. The majority of sandstone in the D-6 unit is distributed as strike-elongate bars trending southwest to northeast across the center of the map area. The interpretation of transgressive bar facies is further based on upward-coarsening and blocky log responses in many of the electric log profiles. This map pattern is interpreted to represent a complex interplay of previous bar deposition now becoming reworked by fluvial channels that have been reestablished by an increase in sediment load supplied from the region to the northwest of the map area.

The D-5 unit contains the greatest sand thicknesses of any of the mapped subunits and is the most depositionally complex unit under study. The overall sandstone geometry consists of northwest-southeast trending, dip-parallel channel facies (Figure 35). Because of the greater thicknesses of mapped sand patterns, it is difficult to distinguish boundaries between individual channels. The thickest development of sandstone consists of a relatively narrow channel feature that runs from northwest to southeast across the study area. This unit represents a complex depositional situation of some reworked bar remnants and probably multiple episodes of fluvial channel deposition. This unit is currently being subdivided into two separate zones, the D-5a and D-5b units, to better understand the evolution of sand distribution and identify discrete channel patterns within this important reservoir unit.

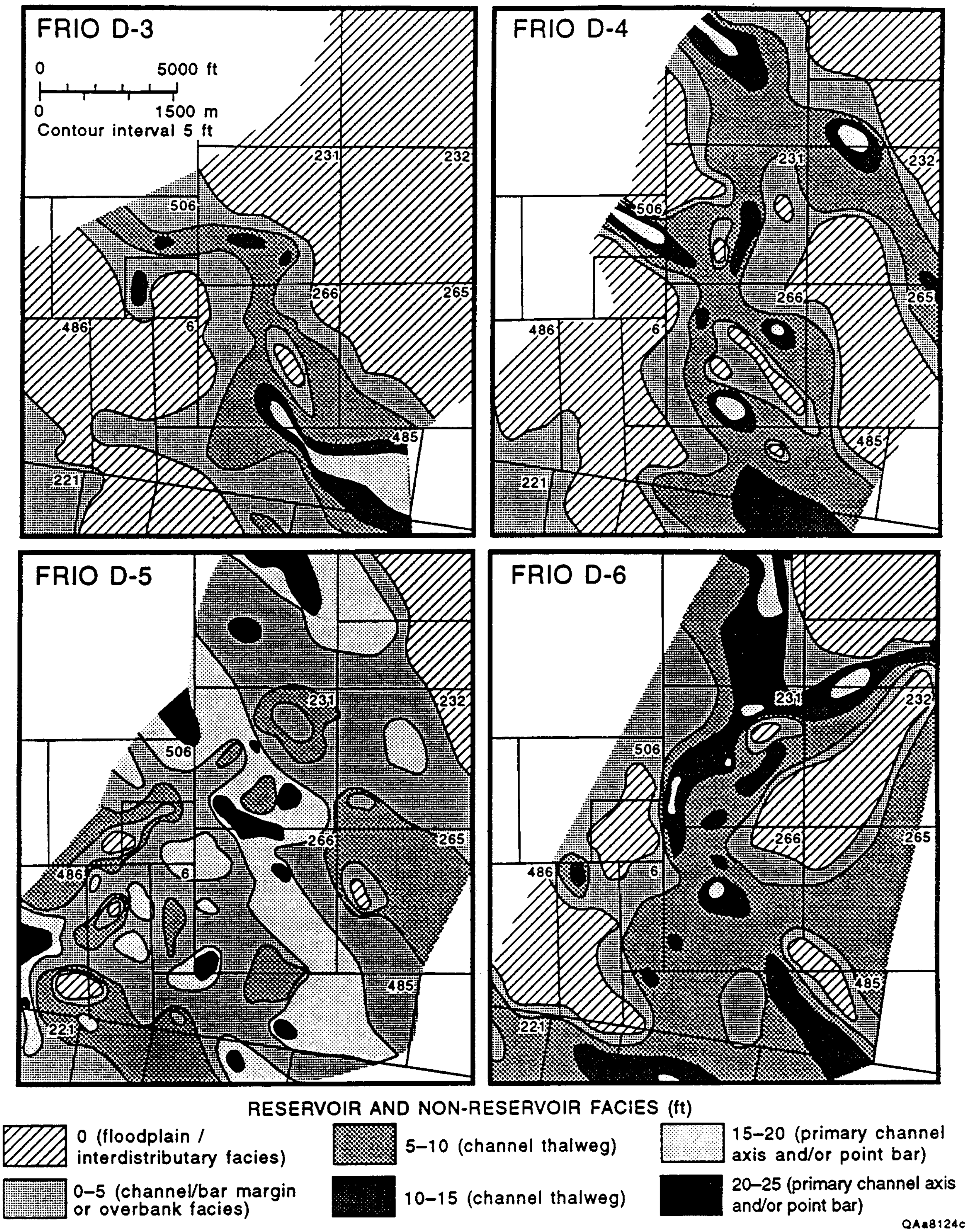


Figure 35. Series of net sandstone isopach and facies maps showing changes in the distribution of facies and sandstone facies geometry for the Frio D-6, D-5, D-4, and D-3 reservoir units.

The uppermost Frio D reservoir subunits represent a return to aggradational sedimentation. Both the D-4 and D-3 units are dominated by dip-elongate fluvial channel deposition (Figure 35). 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.

Application of depositional facies patterns to reservoir studies

Evaluation of net sandstone thickness patterns and facies distributions based on maps constructed over each reservoir subunit indicates a systematic evolution of sediment transport styles. These are, in sequence, (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 upper Frio D-4 and D-3 units. Fluvial-dominated delta settings are sediment-supply-dominated systems, and the retrogradational, back-stepping units developed during deposition of the E-2 to D-6 units most likely reflect a decrease in the amount of sediment being supplied to the system. These different styles of deposition directly affect the reservoir geometry present within each sandstone unit. Aggradational and progradational channel sedimentation creates dip-oriented channel sandstones that may or may not be in communication with each other. Retrogradational units, in contrast, allow reworking of previously deposited sediment into long strike-oriented features that have potential for increased flow communication.

Wireline core porosity and permeability data from reservoir zones in cored wells were posted on individual sandstone isopach and facies maps to identify the lateral distribution of these values between wells with respect to sandstone geometry and depositional facies. Evaluation of these trends is discussed in the next section.

Development of porosity and permeability models

Methods

Permeability is the fundamental rock property that determines fluid-flow characteristics, and accurate characterization of permeability values and their distribution within a hydrocarbon reservoir is the key to understanding past production history and designing future incremental recovery strategies to maximize resource development. Because it can be directly related to productivity, distribution of permeability in a reservoir is a key attribute that may be used to allocate total production to specific geologic units. This is an important concept because there are many situations, especially in older fields, where reservoir production has been combined and reported for multiple sandstone units.

A good understanding of vertical permeability distribution within wells and lateral distribution of permeability between wells is possible when abundant data from routine core analyses are available. Rincon Field is unusual among mature South Texas oil fields in its abundance of available core data. Although the majority of actual core has not been preserved, data from wireline cores in more than 100 wells within the study area (Figure 15) were available. 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 has been demonstrated to be inappropriate for 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.

Rincon conventional core analysis data were grouped by reservoir and by stratigraphic interval during Phase I reservoir studies in order to identify variations in porosity and permeability values between individual reservoir zones and also between lower Frio and middle Frio reservoir groups (Figure 26). Core data available for the Frio D and Frio E reservoir zones were also grouped by reservoir subunit and by reservoir facies. These data groups provide the basis for the identification of means and distribution of values (heterogeneity) for the reservoir attributes of porosity and permeability for sandstone reservoir units and reservoir facies within Rincon field.

Porosity-permeability transforms

Methods

Core data from the Frio D and E reservoirs were evaluated in several ways. First, in order to identify general relationships between the two, porosity and permeability values were cross plotted for the entire data set available from the Frio D and Frio E reservoir zones. Permeability in sandstones is a function of many factors, including porosity, pore type, grain size, sorting, degree of cementation, and type, abundance, and distribution of clay minerals. The range of scatter commonly observed on porosity-permeability cross plots indicates the extent to which factors other than porosity affect permeability. To try to reduce the degree of scatter, core data were divided into smaller groups (1) by reservoir subunit (i.e., D-3. D-4, D-5, D-6) and (2) by reservoir facies, as identified from net sandstone and log facies distribution maps. Facies data were grouped according to channel and bar sandstone facies types as recognized on sandstone isopach maps, and channel facies were further subdivided into vertical subfacies identified from electric log profiles.

Basic statistical analysis of wireline core porosity and permeability data in the Frio D and Frio E reservoir zones was undertaken to recognize relationships between measured permeability with rock characteristics observed in core and facies determined from sand-unit mapping. A data base was constructed that integrated measured porosity and permeability values with their sample depths and corresponding facies and subfacies types identified from map patterns and electric log signatures, respectively. Basic descriptive statistics, including histograms and linear regressions of porosity versus permeability, were calculated for each different subgroup of data.

Porosity and permeability distribution for channel subfacies

In wells with sufficient core data, distinctly different porosity and permeability values were usually recognized for the base, middle, and top portions of an individual channel sandstone unit

(Figure 36). Frequency distributions of porosity and permeability grouped according to vertical position within an individual channel facies unit are shown in Figure 37. Porosity and permeability values exhibit a consistent vertical trend for channel facies with lowest values at channel bases (porosity mean: 16.9%, range 6.9–27.3%; mean permeability: 6 md, range: 0.1–157 md) where development of a mud-chip lag is common. Permeability increases upward through midchannel (porosity mean: 21.2%, range: 8.2–30.7%; permeability mean: 60 md, range: 0.1–1,530 md) and then decreases at channel tops (porosity mean: 18.4%, range: 10.0–27.9%; permeability mean: 14 md, range: 0.1–185 md) where grain size decreases. This pattern was commonly observed in wells throughout the study area.

This vertical trend is very typical of fluvial channel deposits and reflects changes in grain size that normally occur through an upward-fining sequence. The decreased permeability at the bases of channel units is an important factor in determining the level of vertical communication between two channel units that are vertically stacked with no intervening mudstone. Significant porosity and permeability contrasts at the bases of channel deposits are due to the presence of clay clasts and other poorly sorted ductile fragments. If these components are in high enough concentrations and form laterally persistent beds, they may form partial or complete barriers to flow.

Porosity and permeability distribution for primary facies types

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. Frequency distributions of core porosity and permeability values grouped according to these three general facies types are illustrated in Figure 38. Channel units, on average, possess slightly higher values of porosity and permeability (20.5% mean porosity, 60.8 md mean permeability) than the bar sandstone units (mean porosity of 18.5%, mean permeability of 24.4 md). Overbank facies have lower porosities (mean 17.9%) and substantially lower permeabilities (mean 12.3 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

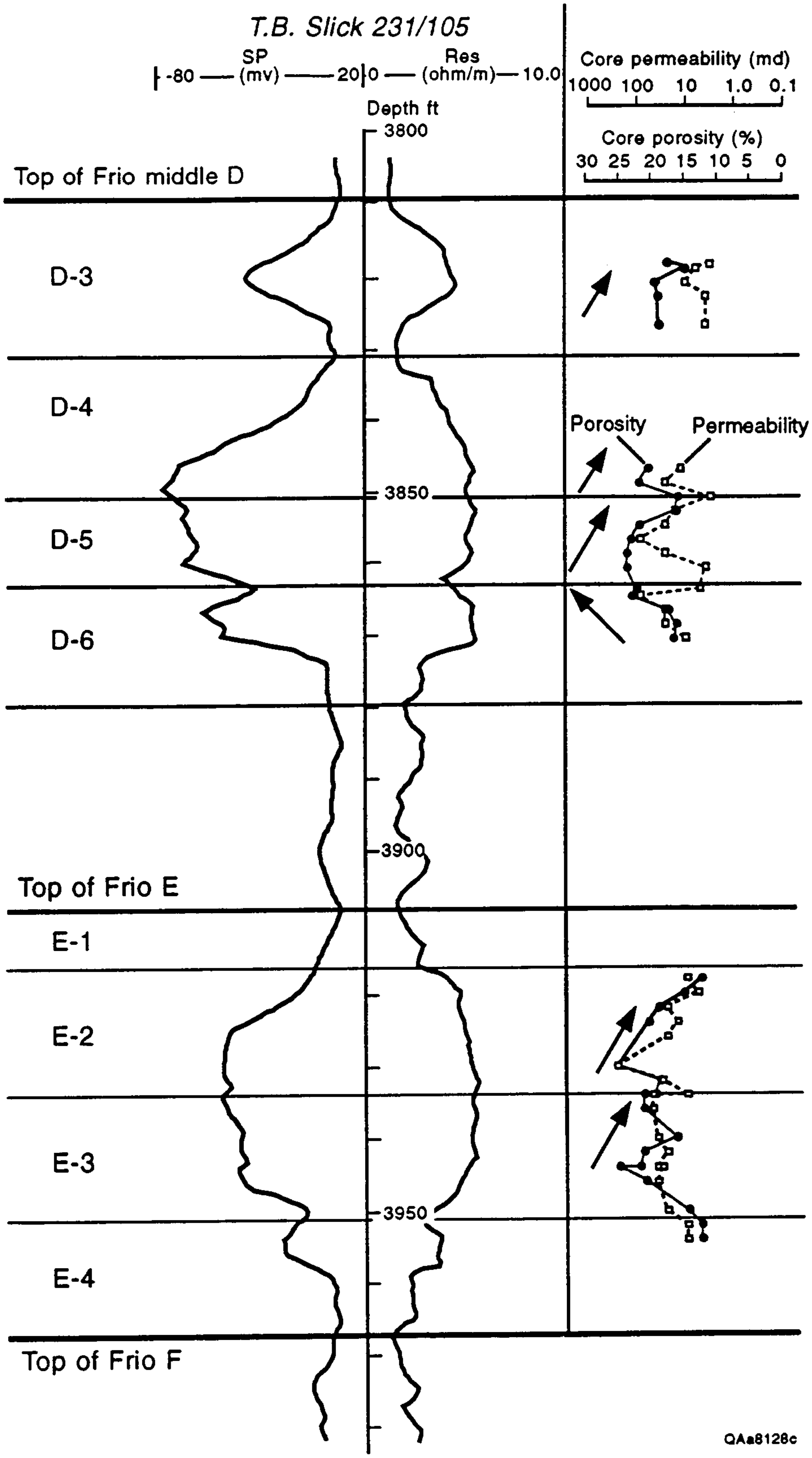


Figure 36. Representative log illustrating Frio D and E reservoir unit nomenclature. Conventional core analysis data posted on the right illustrates porosity and permeability trends commonly observed in each subunit and generally correspond to SP and resistivity bell and funnel curve shapes indicative of upward fining channel sandstones and upward coarsening bar sandstones respectively.

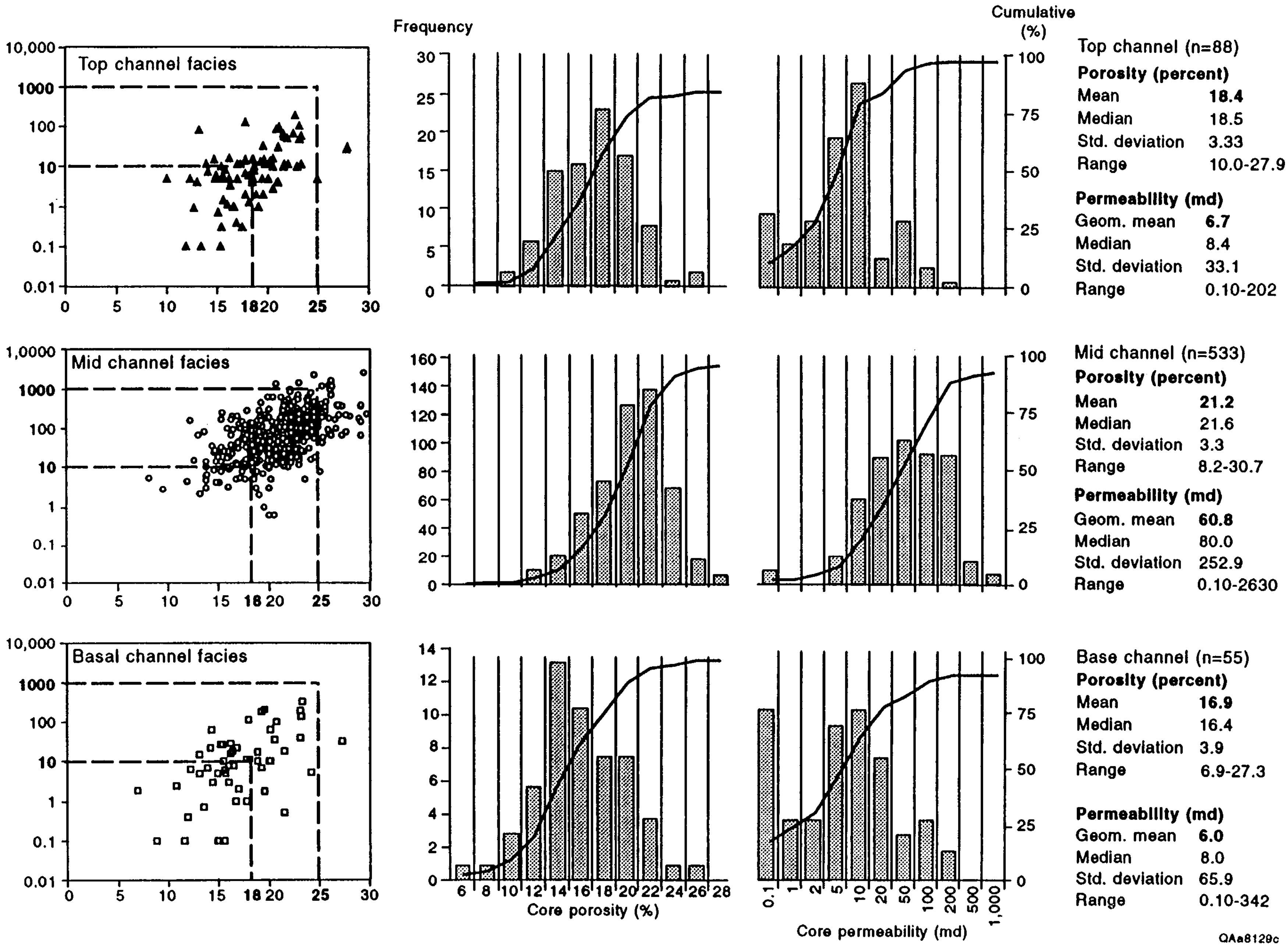
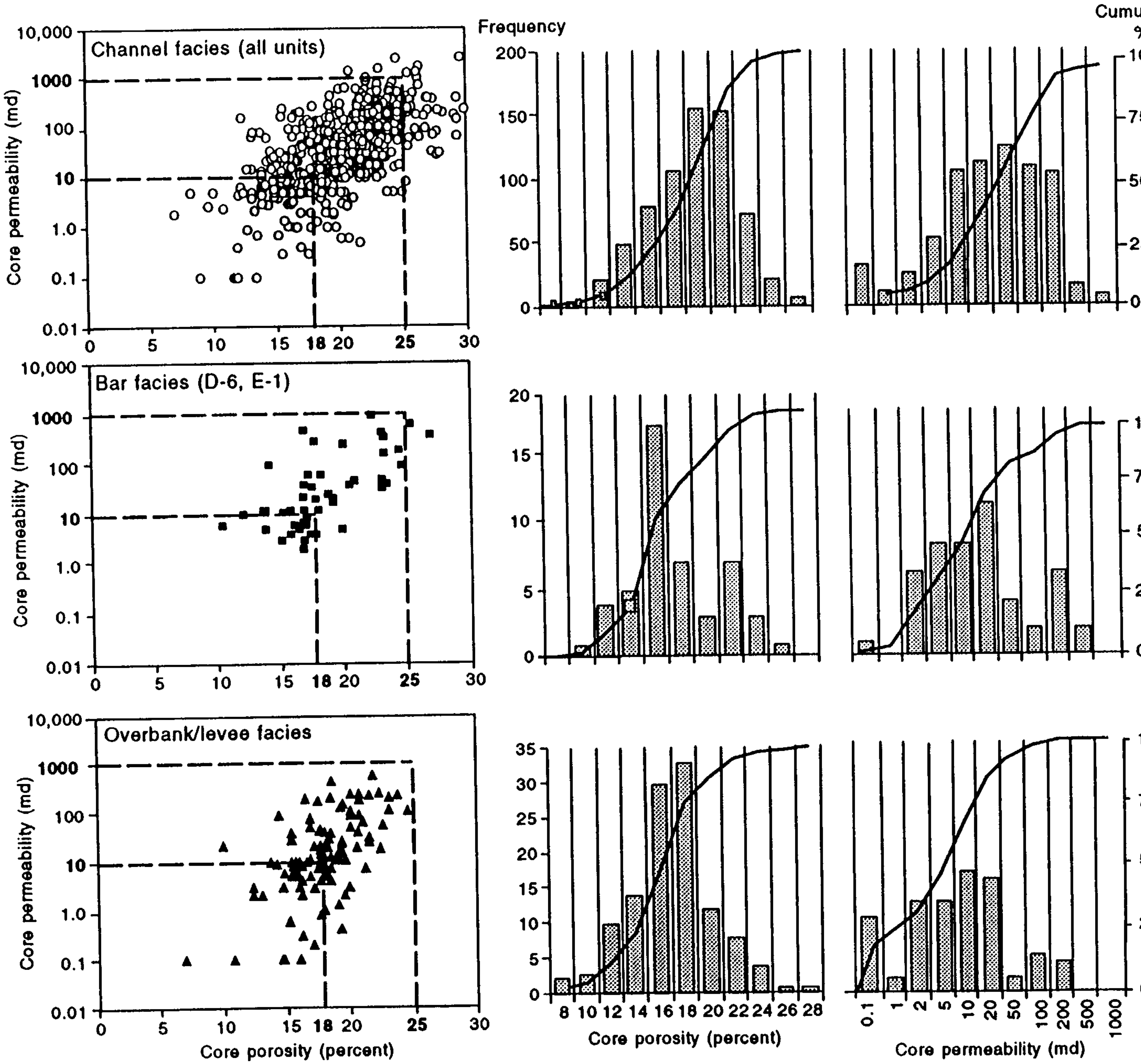


Figure 37. Graphs showing cross-plotted values of core porosity and permeability along with histograms illustrating the distribution of values according to top, middle, and basal channel facies types.



Channel facies
(n=684)

POROSITY (percent)	
Mean	**20.5**
Median	20.9
Std. deviation	3.6
Range	6.9–30.7
PERMEABILITY (md)	
Geom. mean	**60.8**
Median	56.0
Std. deviation	231.4
Range	0.10–2,630

Bar facies
(n=48)

POROSITY (percent)	
Mean	**18.5**
Median	17.6
Std. deviation	3.6
Range	10.3–26.9
PERMEABILITY (md)	
Geom. mean	**24.4**
Median	20.5
Std. deviation	189.8
Range	0.10–955

Overbank/levee facies
(n = 117)

POROSITY (percent)	
Mean	**17.9**
Median	17.9
Std. deviation	3.6
Range	6.9–29.3
PERMEABILITY (md)	
Geom. mean	**12.3**
Median	11.0
Std. deviation	57.5
Range	0.10–250

Figure 38. Graphs showing cross-plotted values of core porosity and permeability along with histograms illustrating the distribution of values according to each of the mapped reservoir facies: aggradational channels, retrogradational bars, and overbank (splay and levee) facies.

units with serrate log responses classified as levee facies. These poorer quality overbank facies generally are not significant reservoirs.

In an effort to identify differences in reservoir quality within channel reservoir facies, channel units mapped for each reservoir subunit were subdivided into three channel facies types: (1) channel margin, (2) channel thalweg, and (3) channel point bar. An example of the distribution of each of these channel facies types is presented in Figure 39. This figure shows the net sandstone isopach map for the D-3 reservoir unit (Figure 39a) and a corresponding identification of lateral channel facies types in Figure 39b. The main trace of the channel is identified by the thicker development of sandstone, in this case, as a single meandering path through the center of the map area. This area is classified as the primary channel axis or channel thalweg. The thinner development of sandstone adjacent to the primary channel region is classified as the channel margin. For simplicity, the channel margin facies is arbitrarily identified as the sandstone present between the 0 and 5 ft isopach. Identification of channel point bars is difficult based on subsurface mapping alone. In the map illustrated in Figure 39, small elongate areas represented by thicker sandstone are commonly located on the inside bend of meander loops defined by the primary trace of the channel. These areas have been classified as belonging to channel point bar facies. This distinction is more easily made on a simple map pattern like the one illustrated in Figure 39. In cases where the sandstone distribution is more complex, location of point bar facies is less obvious or may be completely obscured, and channel facies were grouped into only two groups: either channel margin or primary channel facies units.

These facies designations may contain some mixing of vertical facies types. In an attempt to minimize the effects of low-permeability values skewing the sample population because of excessive sample values measured within the base or top of the unit, mean values were calculated where multiple core data values existed for a given unit. Cross plots of mean porosity and permeability values representing each of the three lateral channel facies are shown in Figure 40. Mean porosity values for all facies types range from 19 to 21 percent. Permeability values appear to be more diagnostic of specific lateral channel facies than are porosity values. Permeability values vary from 47 md (range 4–1,649 md) in channel point bars to 38 md (range 0.1–1,253 md) in the channel thalweg and 10 md

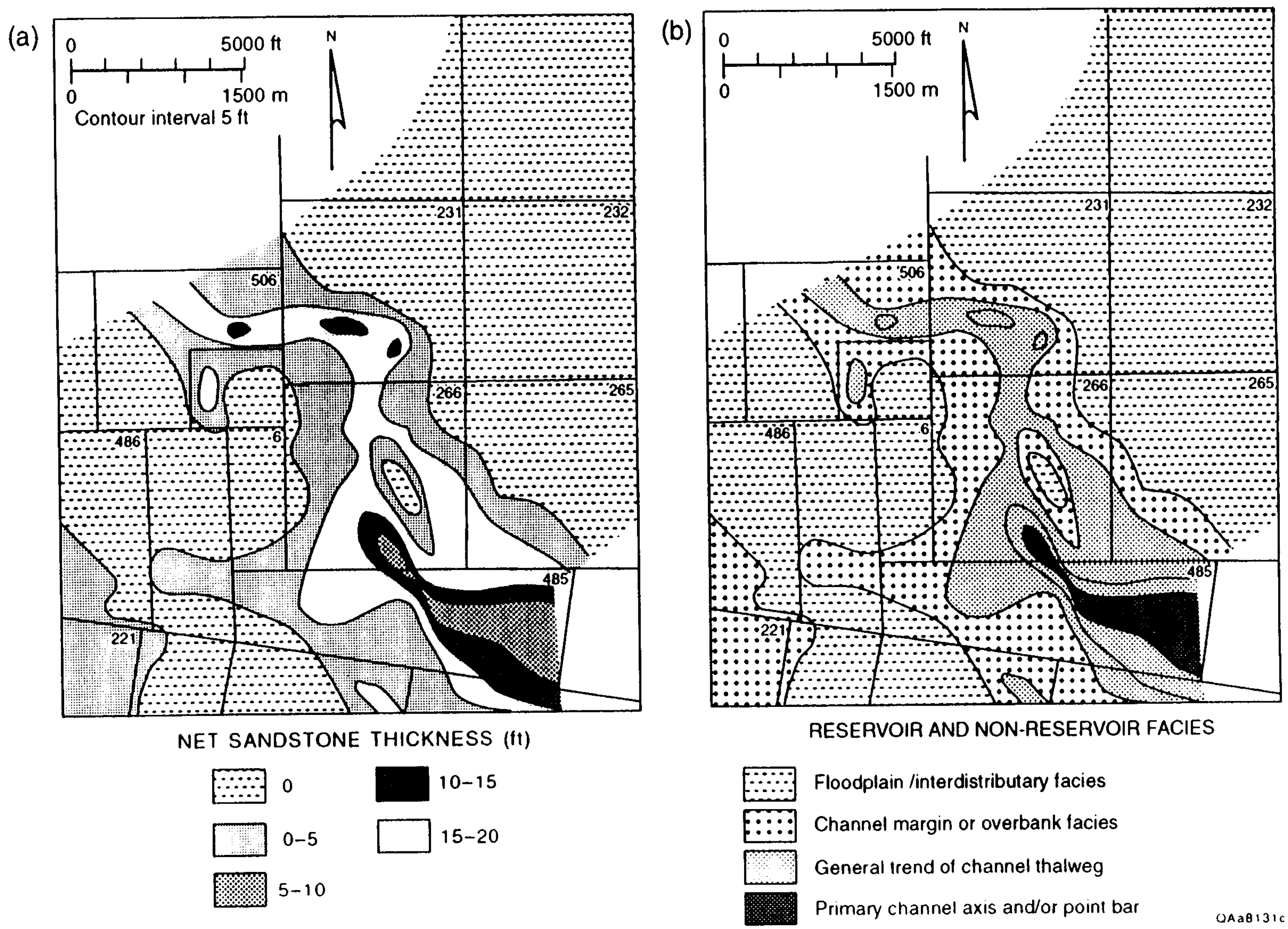


Figure 39. Example of net sandstone isopach map for the D-3 reservoir with corresponding reservoir facies nomenclature.

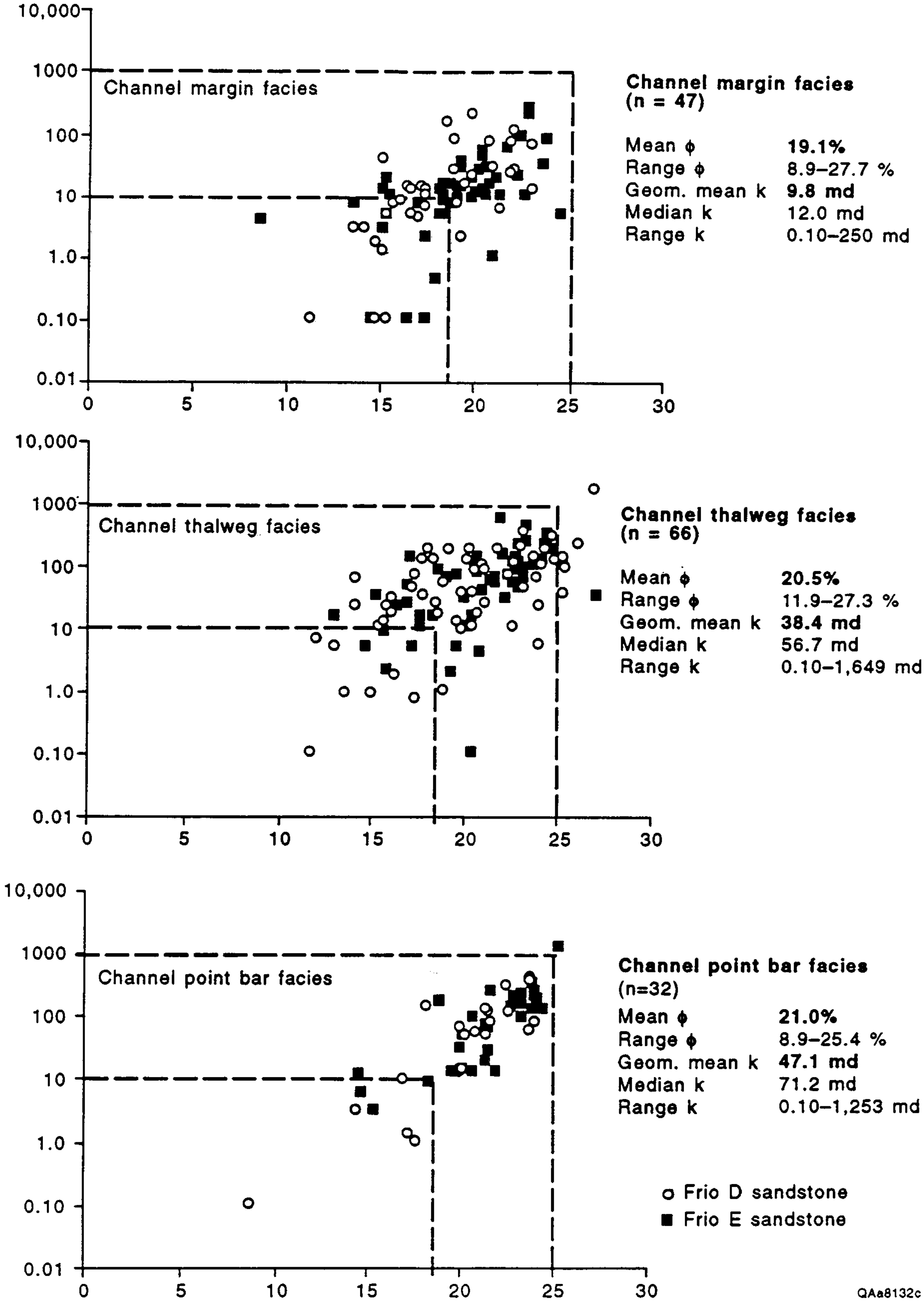


Figure 40. Porosity permeability crossplots and descriptive statistics for various channel subfacies.

(range 0.1–250 md) for channel margins (Figure 40). These values are consistent with grain size variations typically observed within channel sandstone units. The distinct distribution of permeability values by facies type indicates that facies are reasonable predictors of permeability.

To test whether the predictive capability of facies types improves when the data are further sorted by reservoir unit, cross plots and histograms were constructed for facies types from both the E and the D zones. Frequency distributions of porosity and permeability values for each lateral facies type for both the Frio D and Frio E reservoir subunits are illustrated in Figure 41. Histograms of facies types for each reservoir zone illustrate the systematic variation of increasing porosity and permeability from the channel margin to the channel thalweg and channel point bar facies. Mean porosity values are slightly higher for Frio E units than for Frio D units for each facies type (Figure 41). Permeability differences between the two reservoirs are more significant. Mean permeabilities for channel margin units are 10 md for both the D and E reservoirs, but Frio E reservoirs have much higher mean and maximum permeability values in channel thalweg and point bar facies than their counterparts in the Frio D reservoir zone (Figure 41).

Higher permeability values in the upper Frio E reservoir zone may be a result of the retrogradational sedimentation pattern that characterizes deposition of these E reservoir subunits. Decrease of sediment supplied to these channel units may have been responsible for relative back-stepping of dip-oriented channel deposition (see E-2 unit map) and subsequent reworking of sediment deposited in previous channels that flowed across the study area into strike-oriented bars (see E-1 unit map). Initial sediment reworking of E-3 and E-2 reservoir subunits may have cleaned up these sands and may be responsible for the higher permeability values measured in these reservoir units.

Porosity and permeability values for individual reservoir subunits are presented in Table 14, and relationships between porosity and permeability as a function of stratigraphic unit are illustrated in a series of cross plots in Figure 42. No noticeable differences were observed in the relationship between porosity and permeability for each of the channel facies types, and, similarly, no differences in relationships are recognized in reservoir subunits characterized predominantly by channel facies deposition, the D-3, 4, and 5 units and the E-2, 3, and 4 units (Figure 42). Limited amounts of data in

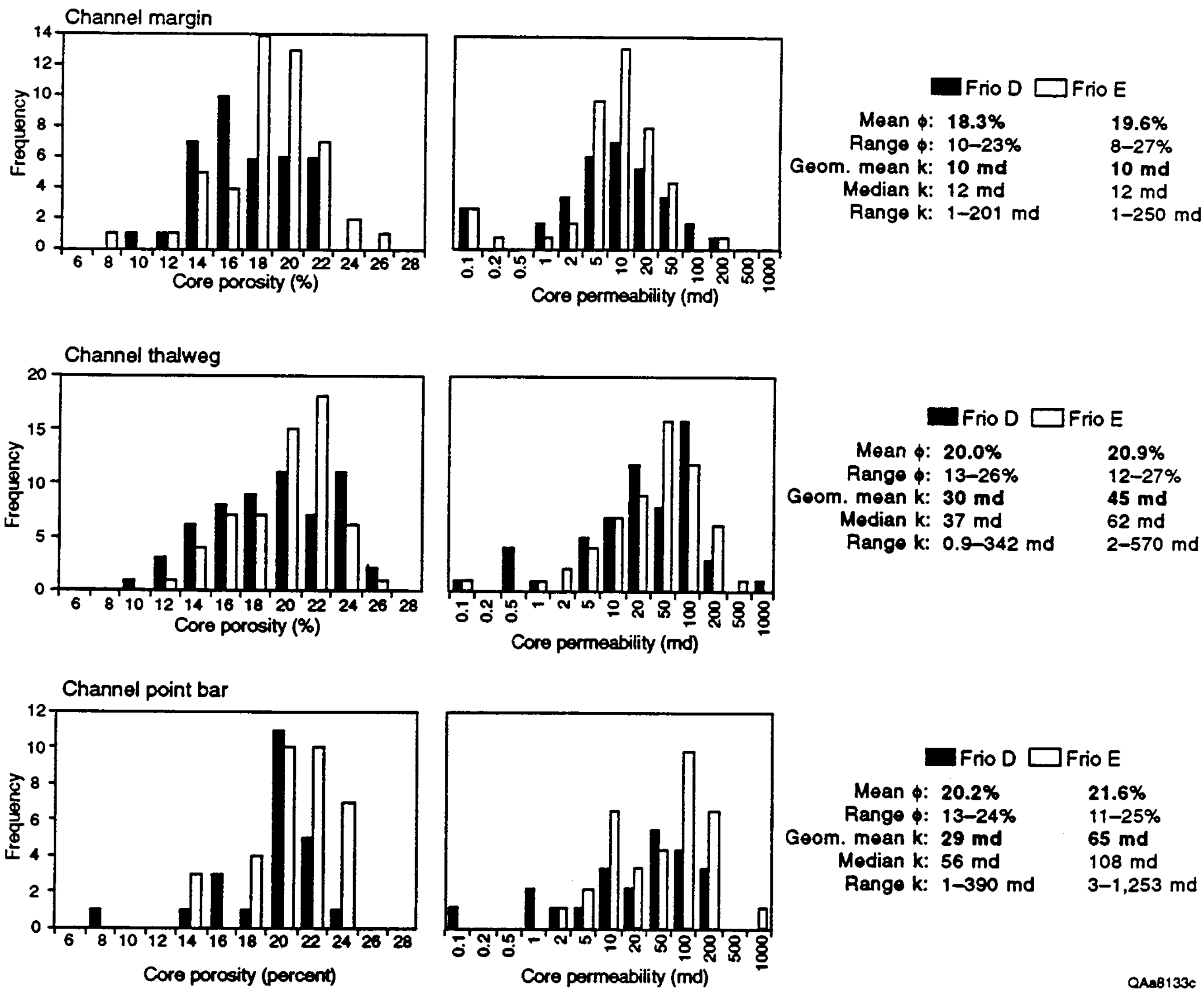


Figure 41. Histograms showing comparison of distribution of porosity and permeability values and statistics for Frio D and Frio E channel sub-facies types.

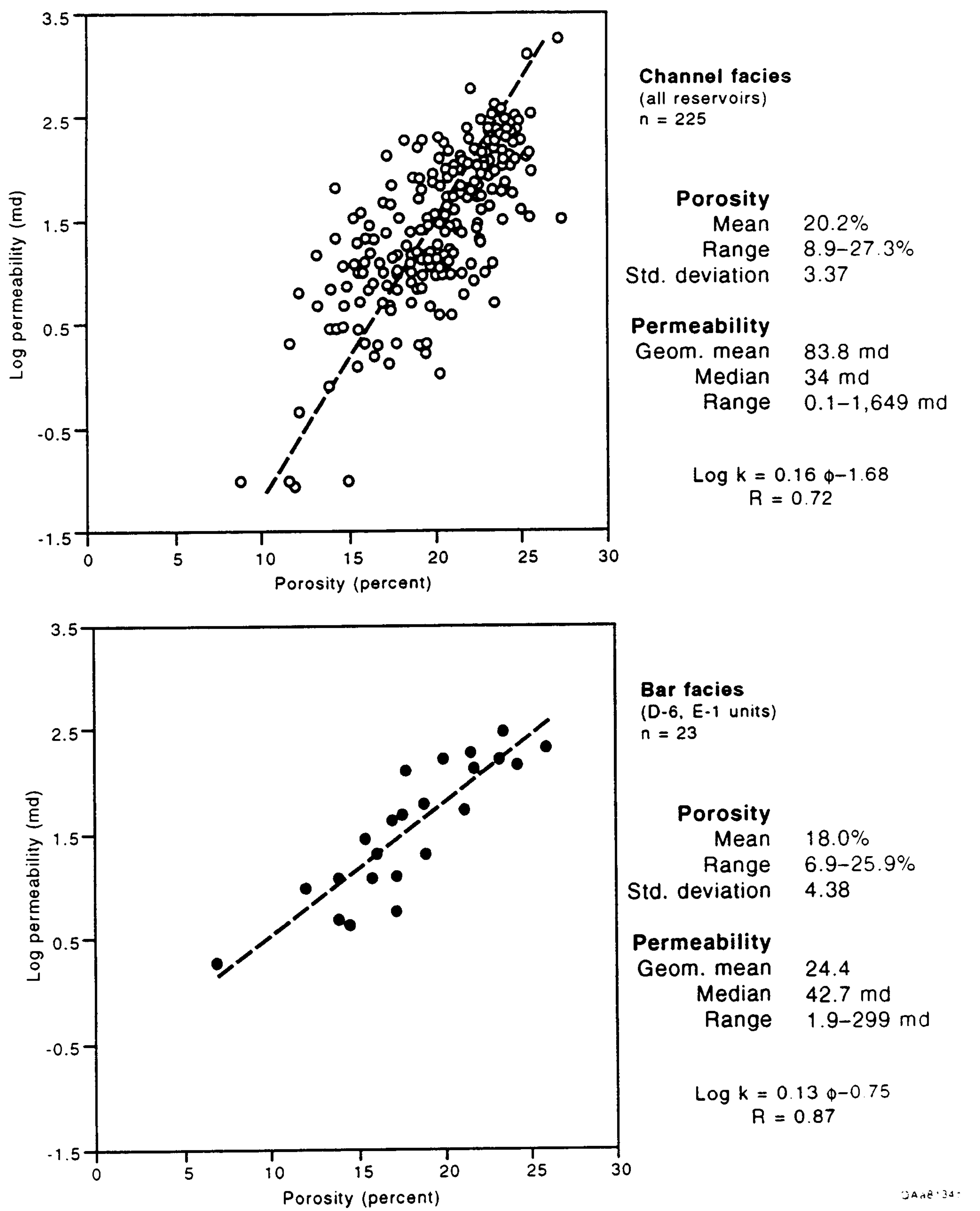


Figure 42. Porosity permeability crossplots and relationships determined for the two primary reservoir facies: channel facies and bar facies.

some of the reservoir units (e.g., D-3, D-4, and E-4 units) preclude the identification of significant variations in porosity and permeability values between successive channel reservoir units. What is recognizable is that the ranges of porosity and permeability values in units that occur during a transition of depositional style reflect more complicated sedimentation. The E-2 unit, located between E-3 aggradational channel deposition and E-1 retrogradational bar deposition, and the D-5 unit, located between progradational deposition of the D-6 unit and aggradational channel deposition of the D-4 unit, both exhibit greater scatter in porosity and permeability data that may be a result of mixed facies distribution.

The relationship between porosity and permeability between channel and bar facies is distinctly different. In the E-1 and D-6 units, the predominant reservoir facies types are strike-oriented bar sandstones, and the distributions of core data values have different slopes than those observed in the other channel-dominated reservoir units. Mean values of porosity and permeability for bar sandstone facies in the E-1 and D-6 reservoir subunits and for all channel facies types in the other reservoir units were cross plotted, and a standard linear regression was performed for each group (Figure 43). The resulting equations for the regression lines demonstrate the different porosity-permeability relationships between these reservoir types. Similar porosity values have a lower corresponding permeability for channel sandstone facies than for bar sandstone facies. These two different relationships will be incorporated into petrophysical porosity modeling.

Porosity-resistivity transforms

Both core porosity and resistivity porosity values were used in the development of a porosity model. Only six wells in the study area have modern log suites that include porosity and sonic log curves. The lack of porosity and sonic log data makes it necessary to derive reservoir porosity completely from SP and resistivity log data.

An example of core and porosity log data over the E reservoir in the T.B. Slick A149 well is shown in Figure 44. 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

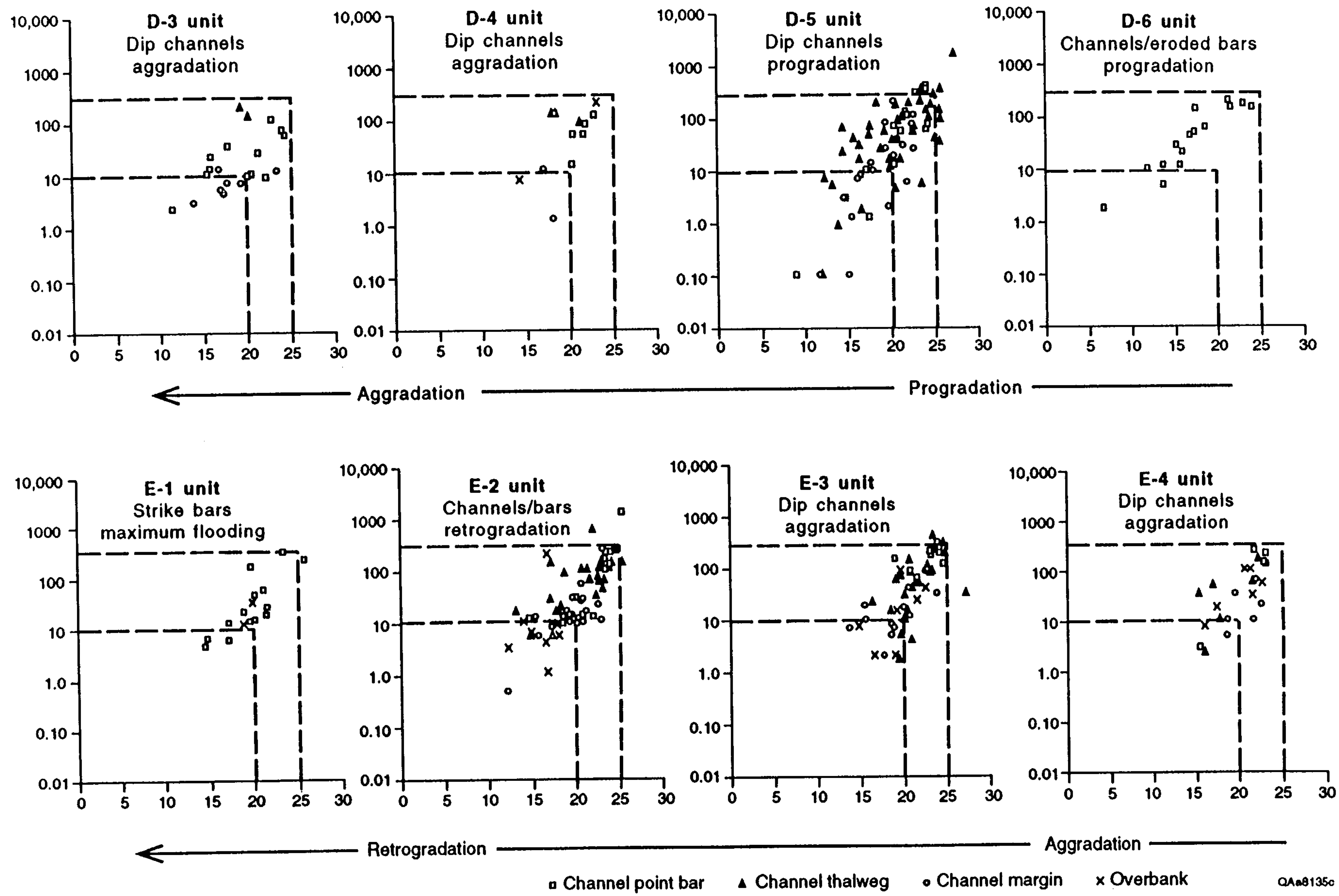


Figure 43. Porosity permeability crossplots for average values from E-4 through D-3 reservoir units showing systematic variation in reservoir attributes in aggradational, retrogradational, and progradational sandstone units.

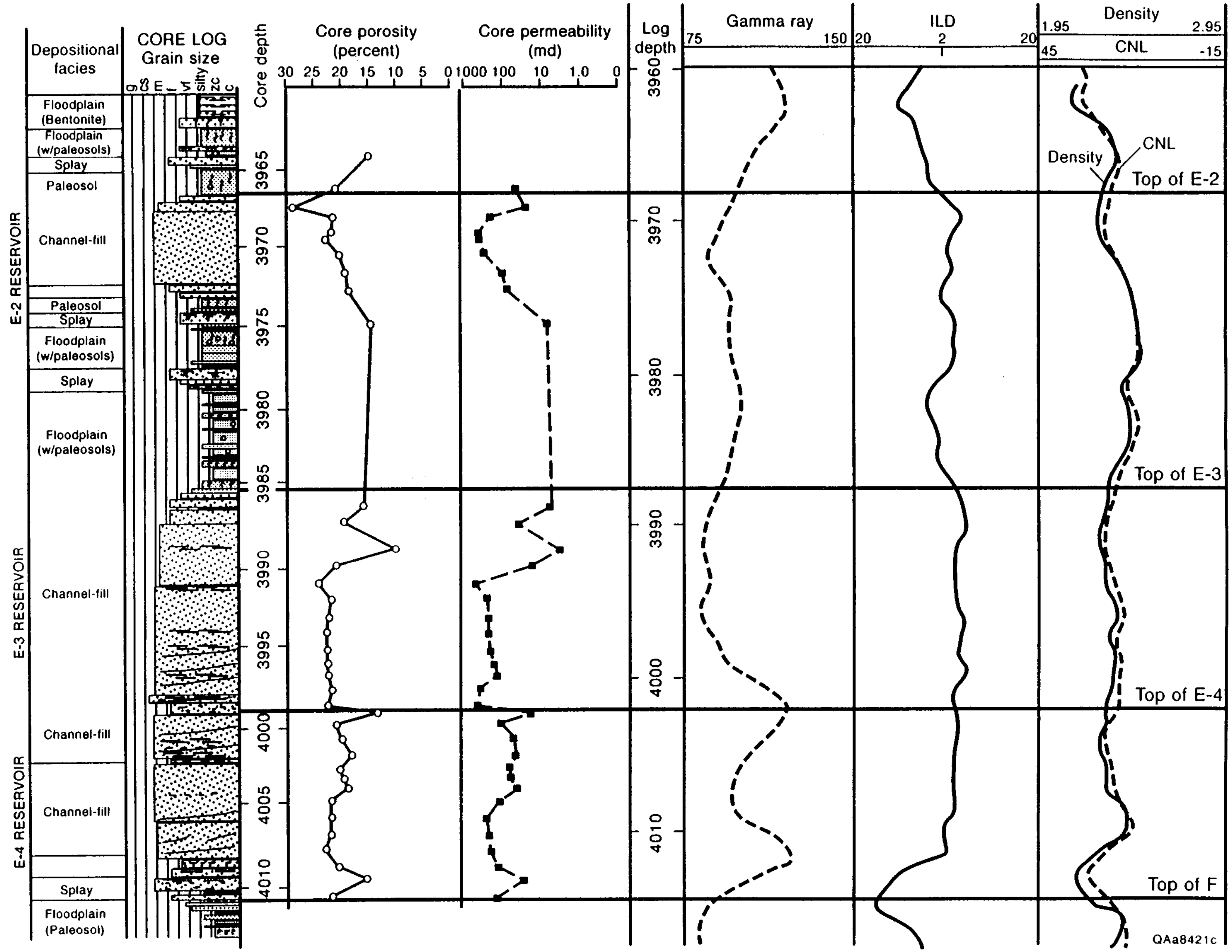


Figure 44. Core graphic log, porosity and permeability data, and gamma ray, induction, and porosity logs for well T.B. Slick 231:149. Refer to Figure 29 for legend explanation.

Table 14: Summary of attribute data for reservoir units and facies types.

		Reservoir Units							
Facies Types	Reservoir Data	E-4	E-3	E-2	E-1	D-6	D-5	D-4	D-3
All facies	Count:	17	55	66			77		21
	Porosity mean:	19.7	20.8	20.1		19.8	20.5	19.6	18.9
	min:	15.3	13.9	12.2			8.8		11.5
	max:	22.5	27.3	25.4			27.1		24.4
	Perm. mean:	26	43	25		49	30	37	14
	max:	135	411	1253		241	390	199	137
	ϕ/k correlation:	.71	.68	.78			.74		.59
Channel margin	Count:	6	13	21			18		7
	Porosity mean:	20.4	19.2	19.4			18.4		17.9
	min:	18.5	13.9	12.2			11.6		13.8
	max:	22.5	23.9	23.1			22.3		23.3
	Permeability mean:	15	12.0	13.0			11.7		6.7
	max:	61	93	250			201		12
	ϕ/k correlation:	.56	.65	.74			.78		.70
Channel thalweg	Count:	6	32	27			40		14
	Porosity mean:	18.3	20.9	21.1			20.1		19.4
	min:	15.3	14.9	13.1			11.9		11.5
	max:	22.3	27.3	25.4			27.1		24.4
	Permeability mean:	40	40	81			49		24
	max:	154	410	570					182
	ϕ/k correlation:	.65	.63	.71			.68		.59
Channel point bar	Count:	5	10	11			16		
	Porosity mean:	21.3	22.6	21.8			20.1		
	min:	15.5	19.1	14.6			8.8		
	max:	23.1	24.6	25.4			24.1		
	Permeability mean:	139	168	96			58		
	max:	246	310	1253			390		
	ϕ/k correlation:	.96	.50	.81			.86		
Reworked bars	Count:				8	15			
	Porosity mean:				19.2	19.8			
	min:				14.5	6.9			
	max:				25.9	24.2			
	Permeability mean:				37.6	49			
	max:				299	241			
	ϕ/k correlation:				.90	.93			

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 are currently being studied in order to develop a model to determine porosity from electric log data. Upon completion of this work, relationships determined for porosity and resistivity will be used to subsequently calculate permeability using the appropriate porosity-permeability relationship that has been identified for each reservoir facies type.

Development of Water Saturation Models

Petrophysical modeling of water saturations has not been completed at the time of preparation of this annual report. Results from petrography and special core analysis will be used to refine estimates of Archie's cementation and saturation exponents. Petrographic examination of thin sections should identify any differences between the Frio D and E reservoir intervals and between different reservoir facies types. On the basis of observations of whole cores, we do not anticipate there being appreciable differences in framework mineralogy within these sandstones. Petrographic studies, along with capillary pressure and formation resistivity measurements on the various reservoir facies types, will be used to identify any variations in pore geometry that may influence saturation.

Delineation of Additional Mobile Oil in Target Reservoirs

Methods and Present Status

Evaluation of net sandstone patterns, facies distributions, core descriptions, and petrophysical data from each of these reservoir zones reveals that each consists of a complex of vertically and/or laterally connected sandstone units that represent separate depositional parasequences. The Frio D and E reservoir zones have similar proportions of channel, overbank, and floodplain facies but very different recovery efficiencies, from 38% in the Frio E sandstone channel system to 29% for the Frio D sandstone interval. A more detailed understanding of the different sandstone architectural styles exhibited by these reservoir zones will help identify the primary controls on the distribution of hydrocarbons and provide direct insight into why the recovery efficiencies for these two zones are so different.

Cumulative production data are commonly among the most accessible and more reliable types of information available from old fields. Areal patterns of reservoir development revealed by isoproduction contours provide insight into 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.

Most well completions in a given reservoir include a stratigraphic interval that spans more than one sand zone, and, as a result, standard cumulative production data on a per well basis usually provide little insight into the stratigraphic distribution of production or the vertical efficiency of the recovery process. The data in Rincon field are no exception, and the results from petrophysical modeling efforts, specifically the identification of permeability distribution, will be used to allocate production stratigraphically and create a three-dimensional understanding of the remaining mobile oil present in these reservoirs.

As a first step in identifying the general distribution of oil production, cumulative production isopach maps were constructed for both the Frio D and E reservoir zones. 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. Net sandstone isopach maps and log facies maps of the eight individual reservoir subunits (Figures 34 and 35) were combined with production data to document completion density present within each subunit. Completion maps prepared for each reservoir subunit also identify locations of wells with completions in vertically adjacent subunits in order to locate possible areas where vertical communication between zones may have influenced production.

Tasks associated with partitioning oil production into individual reservoir subunits are currently in progress. Reservoir areas have been calculated for each of the eight mapped subunits, and volumetric calculations are being computed for each reservoir area. These volumetric calculations will form the basis for more accurate original oil-in-place estimates for each of the reservoir subunits. Results from petrophysical modeling efforts and mapping of permeability distribution will be used to generate values of permeability-feet and $S_o Øh$ that will form the basis of allocating production and mapping the distribution of remaining oil within stratigraphic subunits in these reservoirs. The following discussion presents results from work to date on identifying original oil distribution, evaluating production trends, and assessing the controls of reservoir geometry on production in the Frio D and E reservoirs.

Controls on Reservoir Production in the Frio E Sandstone

Reservoir development history

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 (Figures 33 and 34). 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. In some cases, all of the individual reservoir sands have been interpreted to be in communication.

Secondary waterflooding in the Frio E reservoir zone accounted for 2.5 MMSTB, or nearly 21% 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% porosity and 37.5% water saturation.

Production trends

A map contoured on the top of the Frio D-5 reservoir zone (Figure 45) illustrates the anticlinal feature that characterizes the structural pattern across the study area in the north and central portions of Rincon field. A map showing the distribution of oil production is presented in Figure 46a. The cumulative production map illustrates the trend of high production following along the crest of the structure. After structural position is taken into consideration, the next most obvious control on cumulative production is differences in net thickness of the perforated interval in each well. The total net sandstone isopach map illustrated in Figure 46b indicates greater than average production roughly corresponds to areas of thicker net sandstone that generally follow along channel depositional axes. It is difficult to identify well-developed sedimentation patterns over a composite interval such as this. Evaluation of individual map patterns for the Frio E-4, E-3, E-2, and E-1 reservoir subunits illustrated in Figure 34 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. These conditions may be a controlling factor in the relatively high recovery efficiency (38%) of this reservoir zone. Completion of volumetric calculations for each reservoir subunit, followed by modeling of permeability distribution and apportioning of cumulative oil production to each subunit, is required to identify the stratigraphic distribution of oil and fully understand controls on its accumulation and subsequent production.

Sandstone geometry and reservoir development patterns

Net sandstone isopach data were combined with log facies interpretations to create maps for the E-4 through E-1 units to document the distribution of sandstone and depositional facies within each reservoir subunit. Reservoir development within each unit was indicated by identifying wells with completions within the stratigraphic interval that comprises each unit. In addition, wells were identified

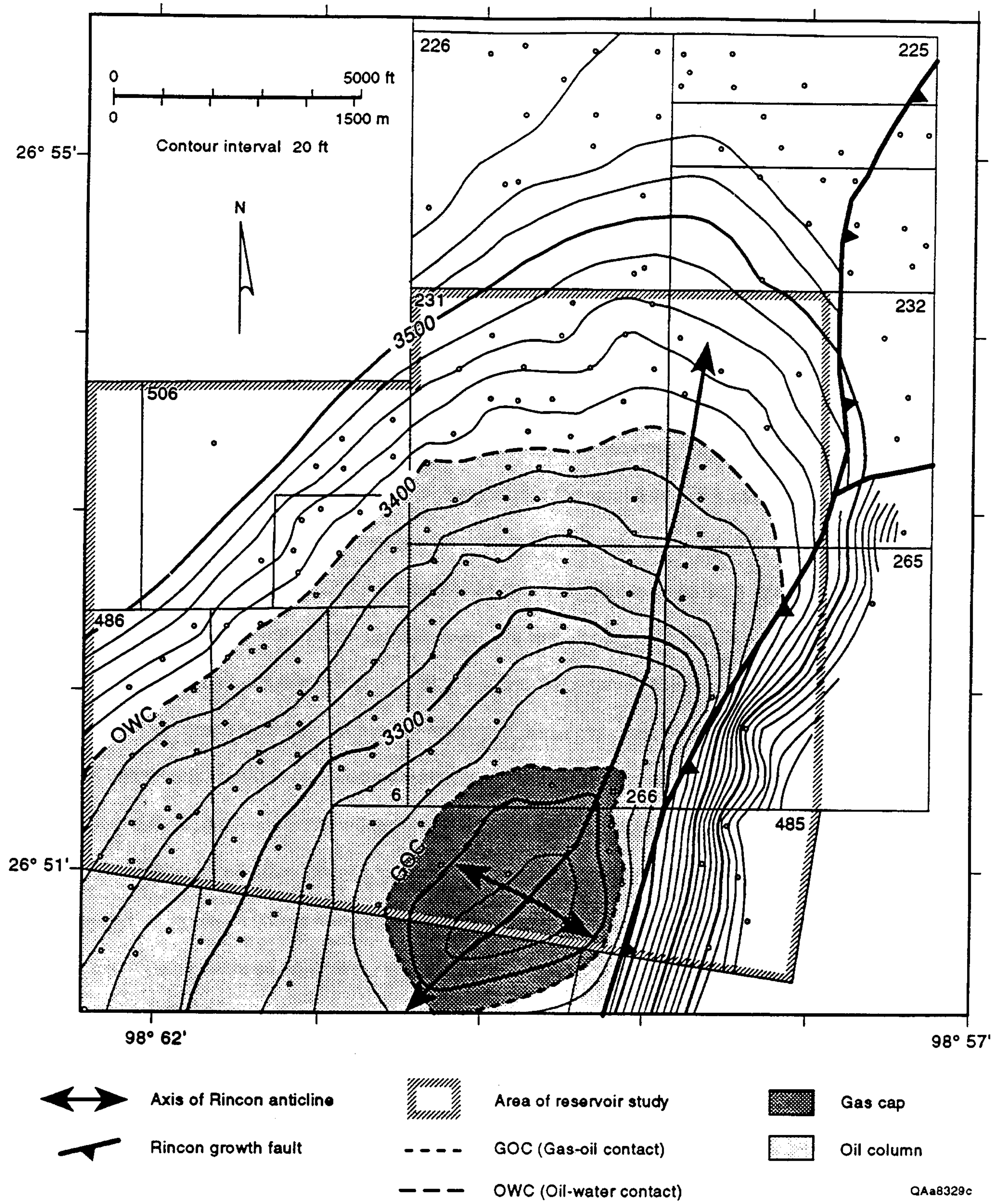


Figure 45. Representative structure map for the D-5 reservoir zone in Rincon field illustrating the crestal portion of the Rincon anticline and presence of a gas cap. The productive Frio section is bounded to the east by the Rincon fault, a down-to-the-east growth fault that developed in association with development of the Vicksburg Fault Zone.

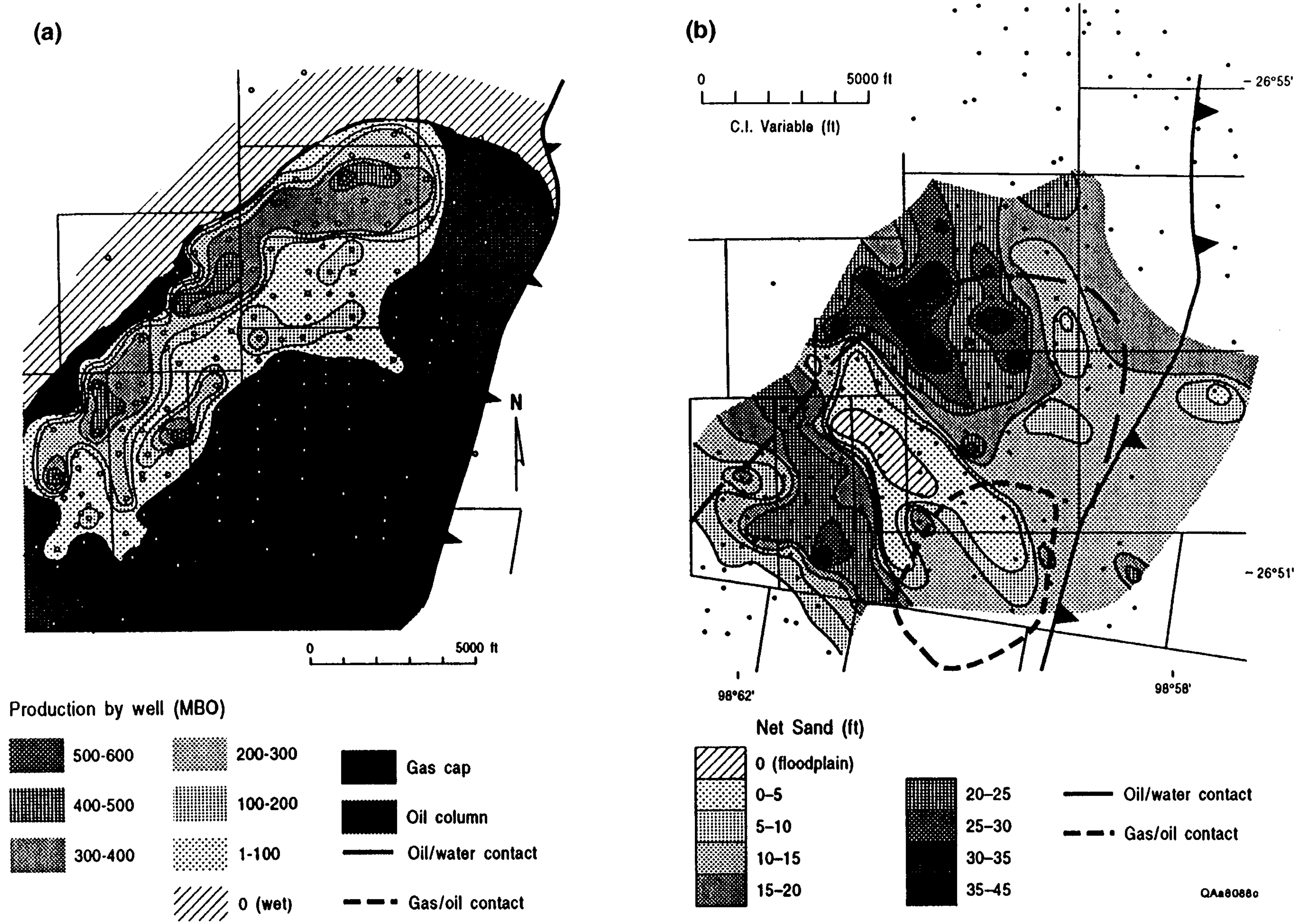


Figure 46. Cumulative oil production map for the entire Frio E reservoir zone, compared with Isopach map from the total E sandstone reservoir zone showing distribution of net sandstone thickness and depositional geometry. The strike-oriented component observed in the updip portion of the mapped channel units may be responsible for increased flow-communication between channels along the crest of the structure and therefore explain the relatively high recovery efficiency (38%) of the E reservoir.

that were not perforated within the mapped zone but that 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 47 through 50.

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 nonreservoir floodplain facies (Figure 47). 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 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 and 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 (Figure 48). 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 these two northern channels. Many additional wells have been completed in a vertically subadjacent 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 E-3 reservoir. Some of this production will likely be apportioned to E-4 sandstones after completion of our revised volumetrics and modeling of the distribution of permeability and saturations.

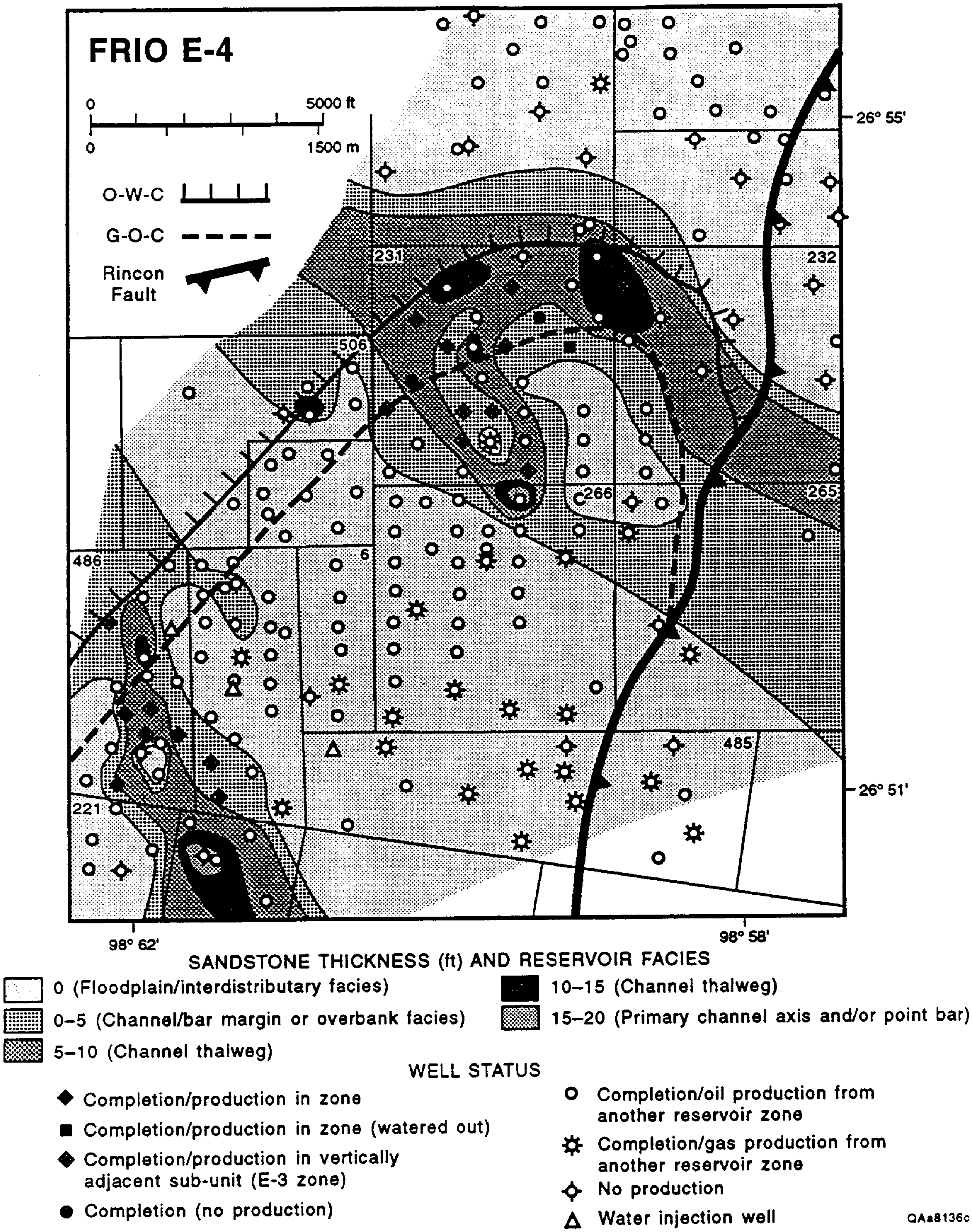


Figure 47. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development in the Frio E-4 reservoir unit.

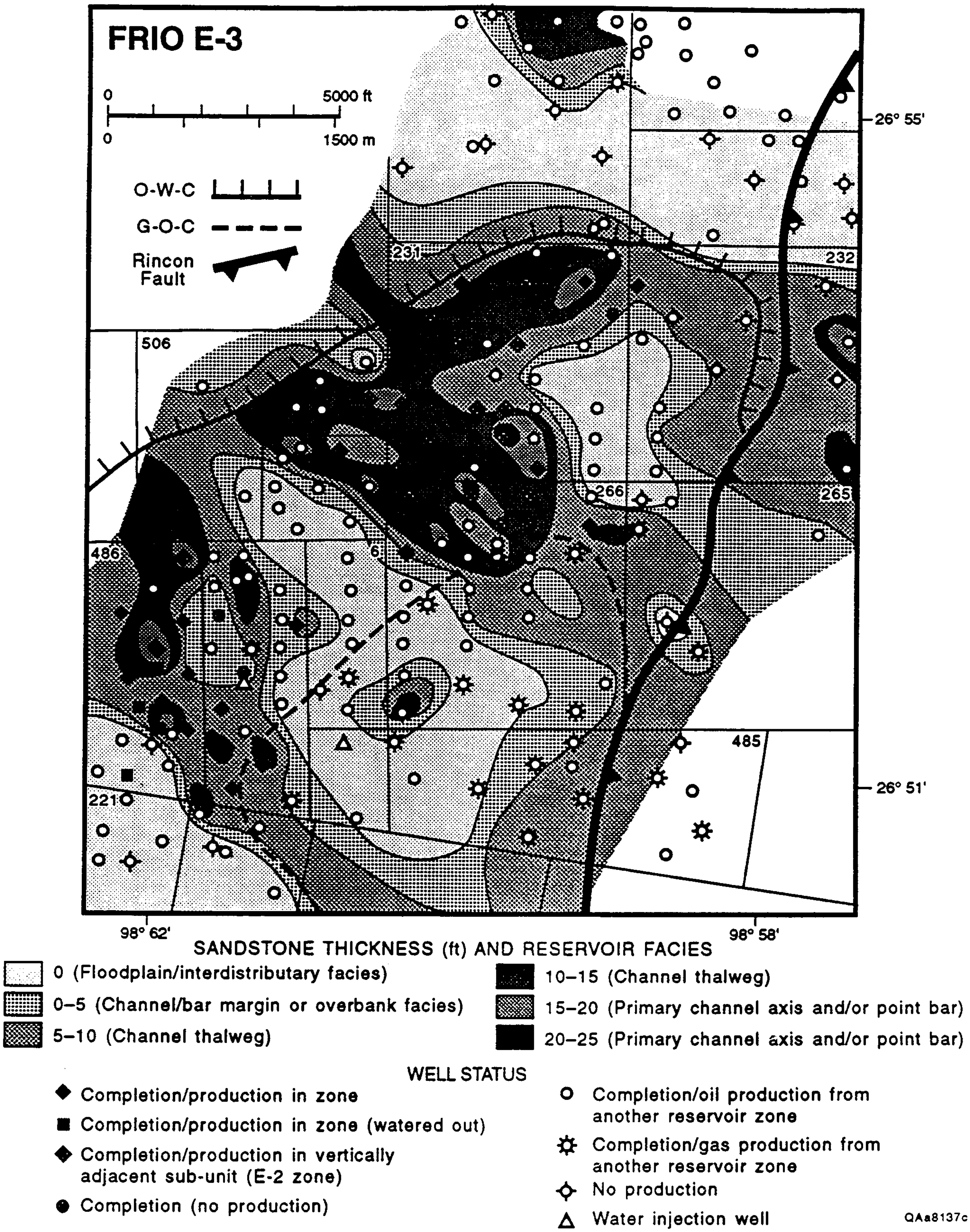
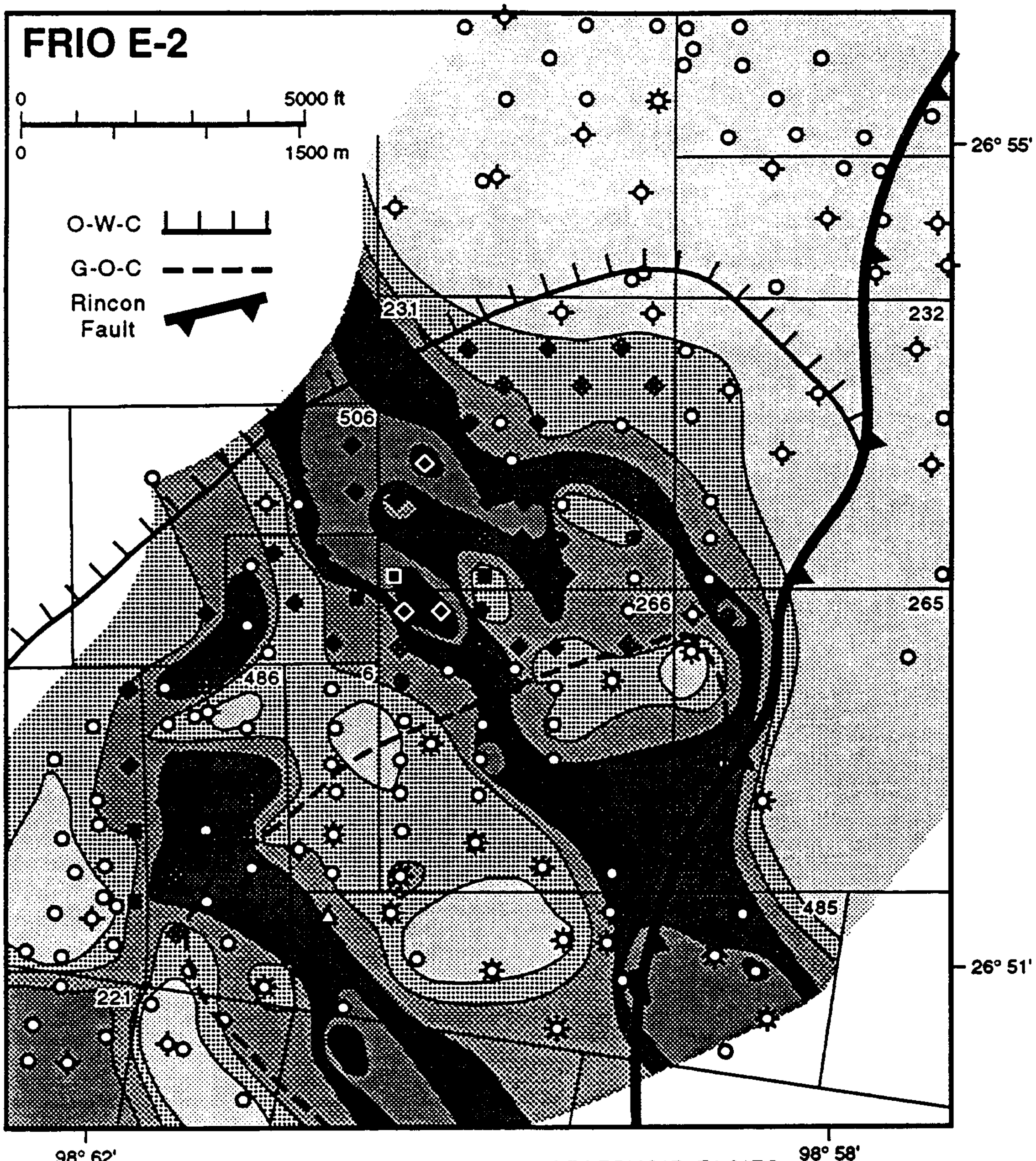


Figure 48. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development in the Frio E-3 reservoir unit.



SANDSTONE THICKNESS (ft) AND RESERVOIR FACIES

- 0 (Floodplain/interdistributary facies)
- 0–5 (Channel/bar margin or overbank facies)
- 5–10 (Channel thalweg)
- 10–15 (Channel thalweg)
- 15–20 (Primary channel axis and/or point bar)
- 20–25 (Primary channel axis and/or point bar)

WELL STATUS

- ◆ Completion/production in zone
- ■ Completion/production in zone (watered out)
- ◆ Completion/production in vertically adjacent sub-unit (E-1 zone)
- ■ Completion/production in vertically adjacent sub-unit (E-3 zone)
- ● Completion (no production)
- O Completion/oil production from another reservoir zone
- ☼ Completion/gas production from another reservoir zone
- ⌖ No production
- △ Water injection well

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Figure 49. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development in the Frio E-2 reservoir unit.

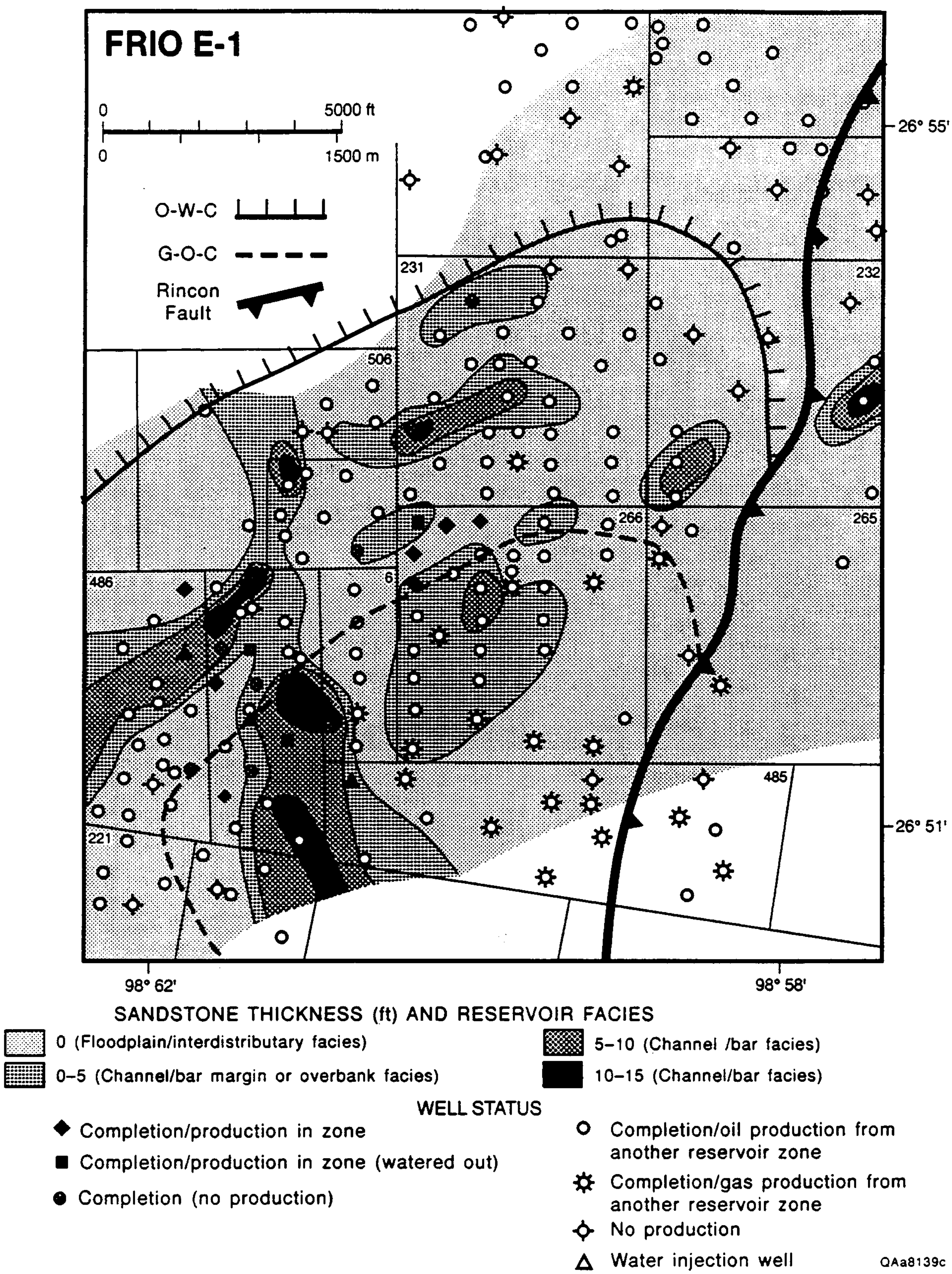


Figure 50. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development in the Frio E-1 reservoir unit.

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 (Figure 49) 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 sand facies that represent some of the highest permeability values (1,250 md+) measured in the field (see Figure 43). Present production allocation indicates that the E-2 unit is also by far the most prolific oil reservoir sandstone 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 operator has interpreted that the E-1 and E-2 sandstones are 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 suggest that the E-1 sandstone was deposited in a retrogradational cycle where preexisting channel units have been eroded and reworked into a series of strike-elongate bar sands that cover most of the mapped study area (Figure 50). 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-1 and E-2 reservoir units than previously assumed. A summary of characteristics, including reservoir facies, sandstone geometry, petrophysical attributes, and key production data for E reservoirs, is provided in Table 15.

Controls on Reservoir Production in the Frio D Sandstone

Reservoir development history

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 (Figure 27). 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. Pressure and production histories indicate that these sands, in many places, form a single large communicating reservoir.

Table 15: Summary of reservoir characteristics for the Frio E reservoir subunits.

Production summary for Frio E reservoir Zone	E-4	E-3	E-2	E-1
Reservoir sedimentology				
Dominant facies type	Channels	Channels	Mixed	Bars
Sedimentation style	Aggradation	Aggradation	Mixed	Retrogradation
Reservoir geometry				
Wells with >0 net sandstone	49	102	109	39
Mean net sandstone thickness	7	10	10	6
Maximum net sandstone thickness	21	24	30	16
Petrophysical attributes				
Mean sandstone porosity	19.7	20.8	20.1	19.2
Geometric mean permeability	26	43	25	18
Max permeability	135	411	1253	299
Reservoir development				
Completed zones	21	50	64	14
Producers	1	21	46	6
MBO produced	3	3100	7517	881
Ratio of well completions/ sandstone penetrations	**0.43**	**0.49**	**0.59**	**0.36**

Frio D sandstones have similar reservoir attributes as Frio E reservoirs (average porosity of 25.2%, S_W of 40.5%, and estimated OOIP of approximately 35 MMSTB) but a lower recovery efficiency of 29%. Waterflooding attempts in this reservoir zone accounted for secondary recovery amounting to only 2% of total D production. These disappointing results were attributed by the field operator to the heterogeneous nature of the D sandstone interval.

Production trends

Maps showing the distribution of oil production in the D zone (Figure 51a) show a similar distribution as was observed in the E reservoir zone, with production "hot spots" oriented along strike

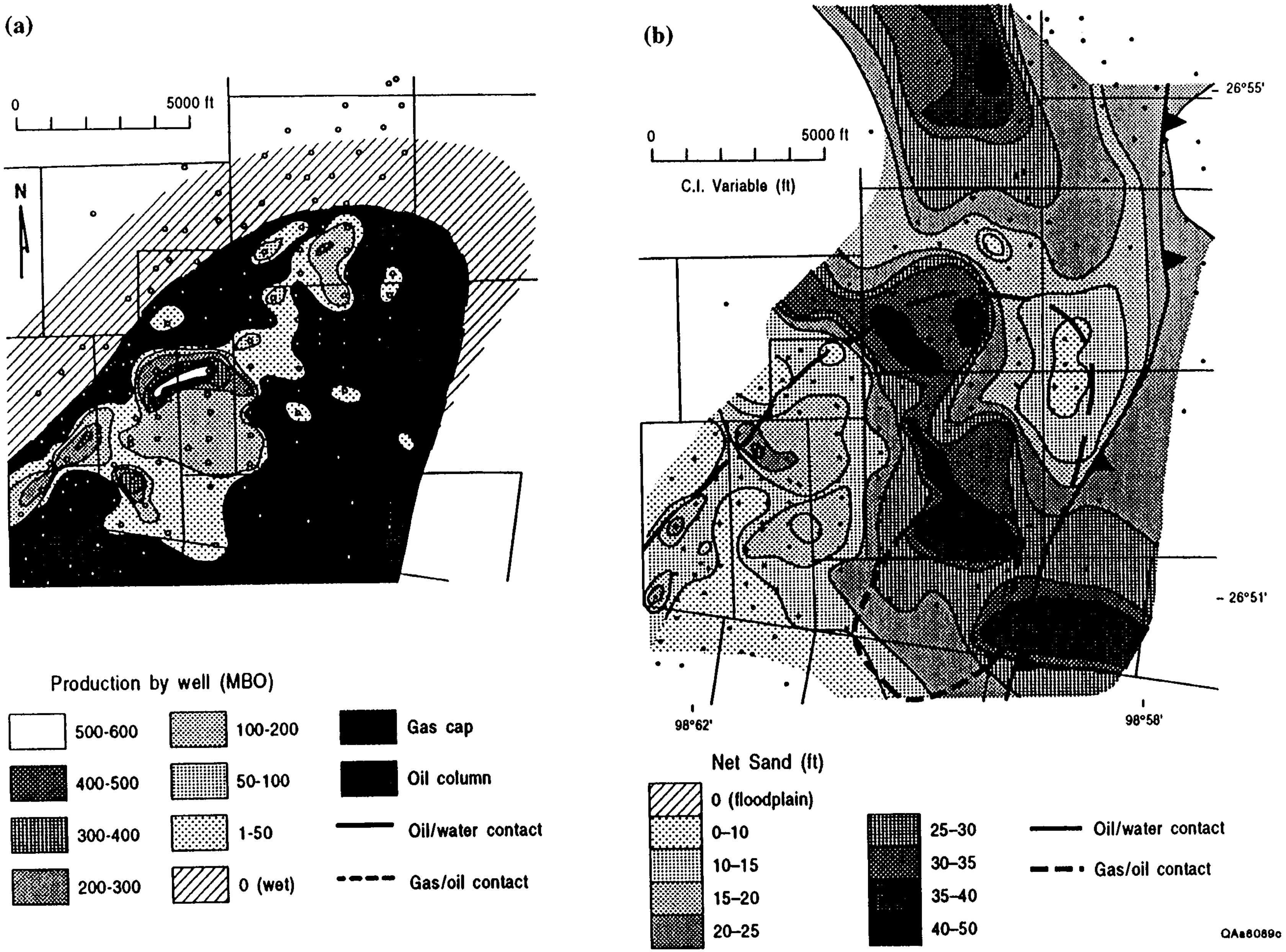


Figure 51. Cumulative oil production map for the middle Frio D reservoir zone, compared with Isopach map from the total D reservoir sandstone. The dip-elongate nature of D sandstone deposition increases likelihood for compartmentalization in this reservoir zone that has an overall recovery efficiency of only 29%.

parallel to the crest of the anticlinal structure. Areas of high production within the D reservoir appear to be much more isolated than was observed on the E cumulative production map (Figure 46). The total net sandstone thickness map for the combined D interval shown in Figure 51b illustrates the strongly dip-oriented pattern of the composite D sandstone interval, which has an estimated recovery efficiency of only 29%. The stratigraphic complexity of this interval of vertically stacked and laterally coalescing sand lobes provides ideal conditions for the isolation of oil accumulations in multiple reservoir compartments, many of which may be incompletely drained or completely untapped. Detailed characterization of each of the D reservoir subunits should reveal causes of stratigraphic heterogeneity that have resulted in compartmentalization of oil volumes and identify areas with high potential for containing undeveloped resources.

Sandstone geometry and reservoir development patterns

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 52 through 55, and a summary of important reservoir characteristics determined for each of the four D reservoir units is provided in Table 16. 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 (Figure 52). 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 complex pattern of variable sandstone thicknesses in the center of the D-6 unit map area is currently being evaluated in detail by the construction of a series of small-scale (5" log) cross sections across the central portion of the D reservoir zone. 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.

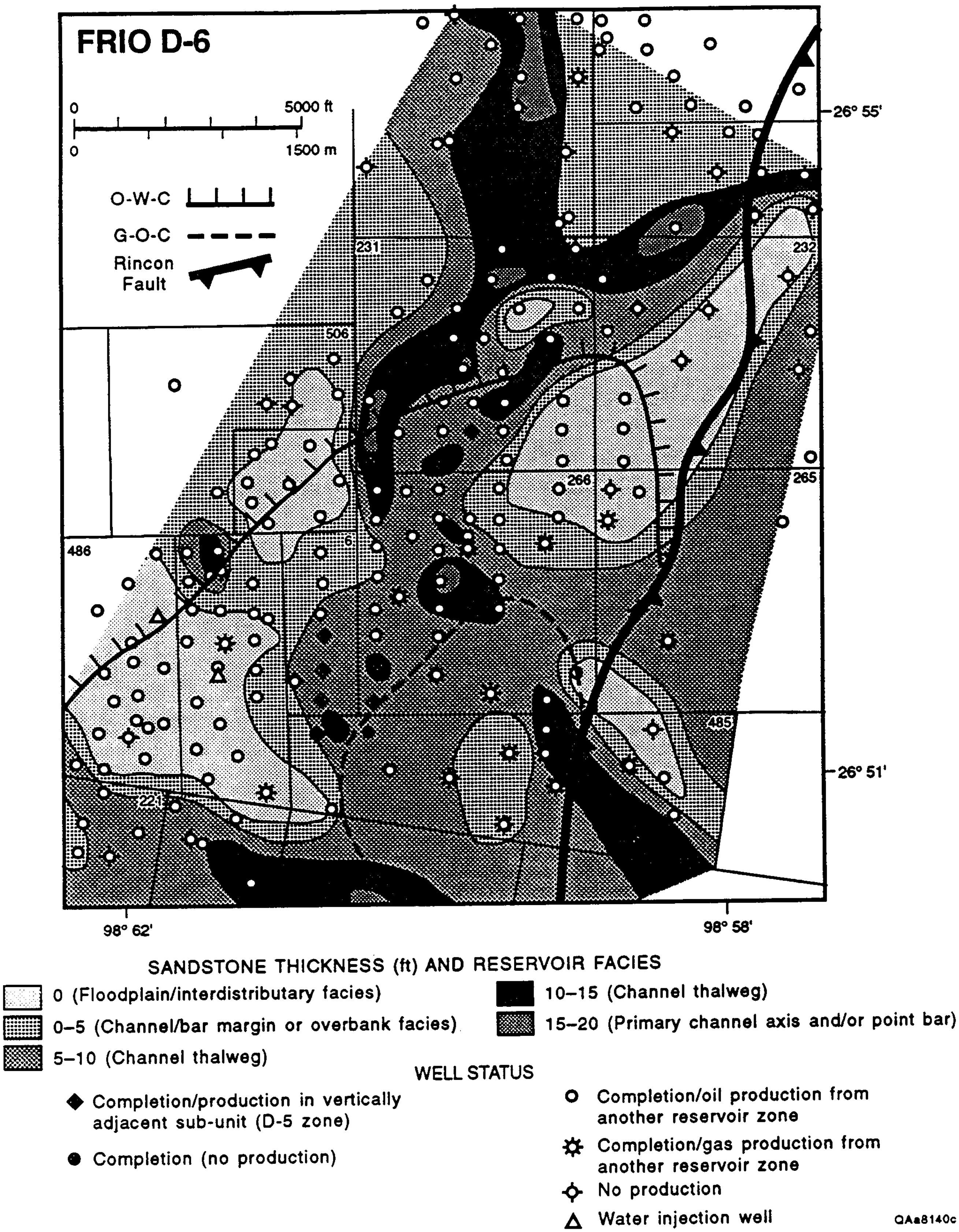


Figure 52. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development in the Frio D-6 reservoir unit.

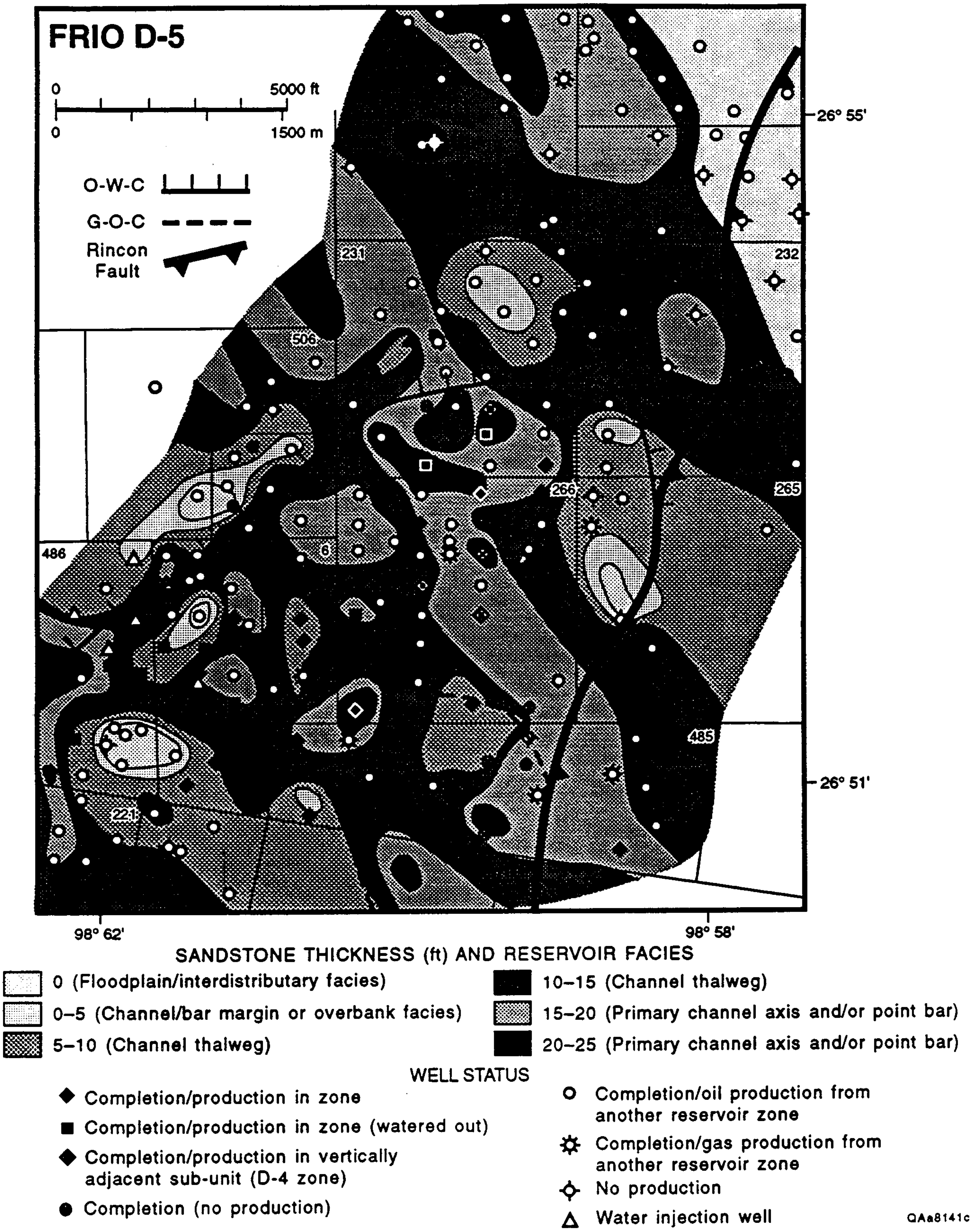
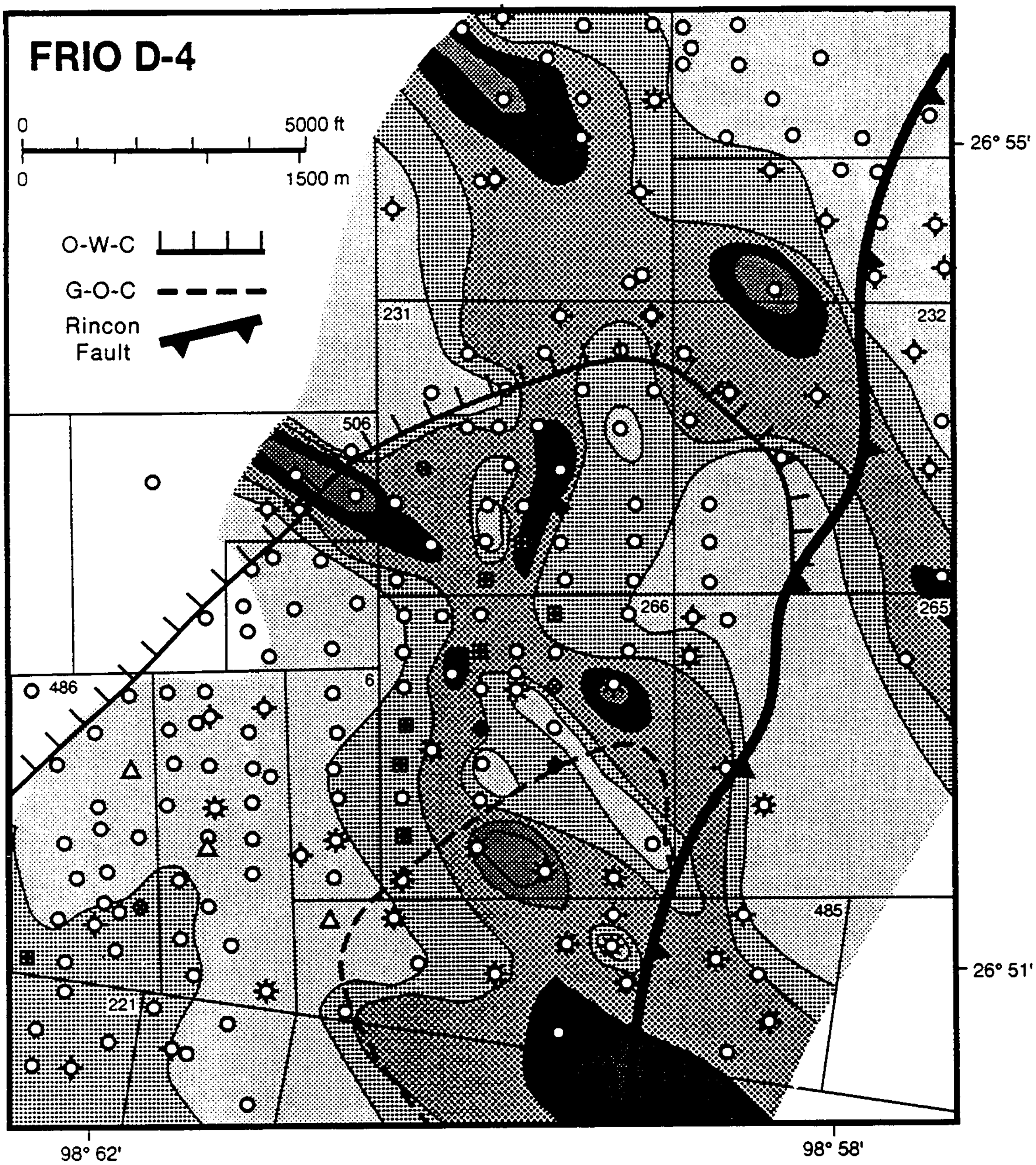


Figure 53. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development in the Frio D-5 reservoir unit.



SANDSTONE THICKNESS (ft) AND RESERVOIR FACIES

- 0 (Floodplain/interdistributary facies)
- 0–5 (Channel/bar margin or overbank facies)
- 5–10 (Channel thalweg)
- 10–15 (Channel thalweg)
- 15–20 (Primary channel axis and/or point bar)

WELL STATUS

- ◆ Completion/production in zone
- ■ Completion/production in zone (watered out)
- Completion/production in vertically adjacent sub-unit (D-5 zone)
- ⊗ Completion (no production)
- ○ Completion/oil production from another reservoir zone
- Completion/gas production from another reservoir zone
- No production
- △ Water injection well

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Figure 54. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development in the Frio D-4 reservoir unit.

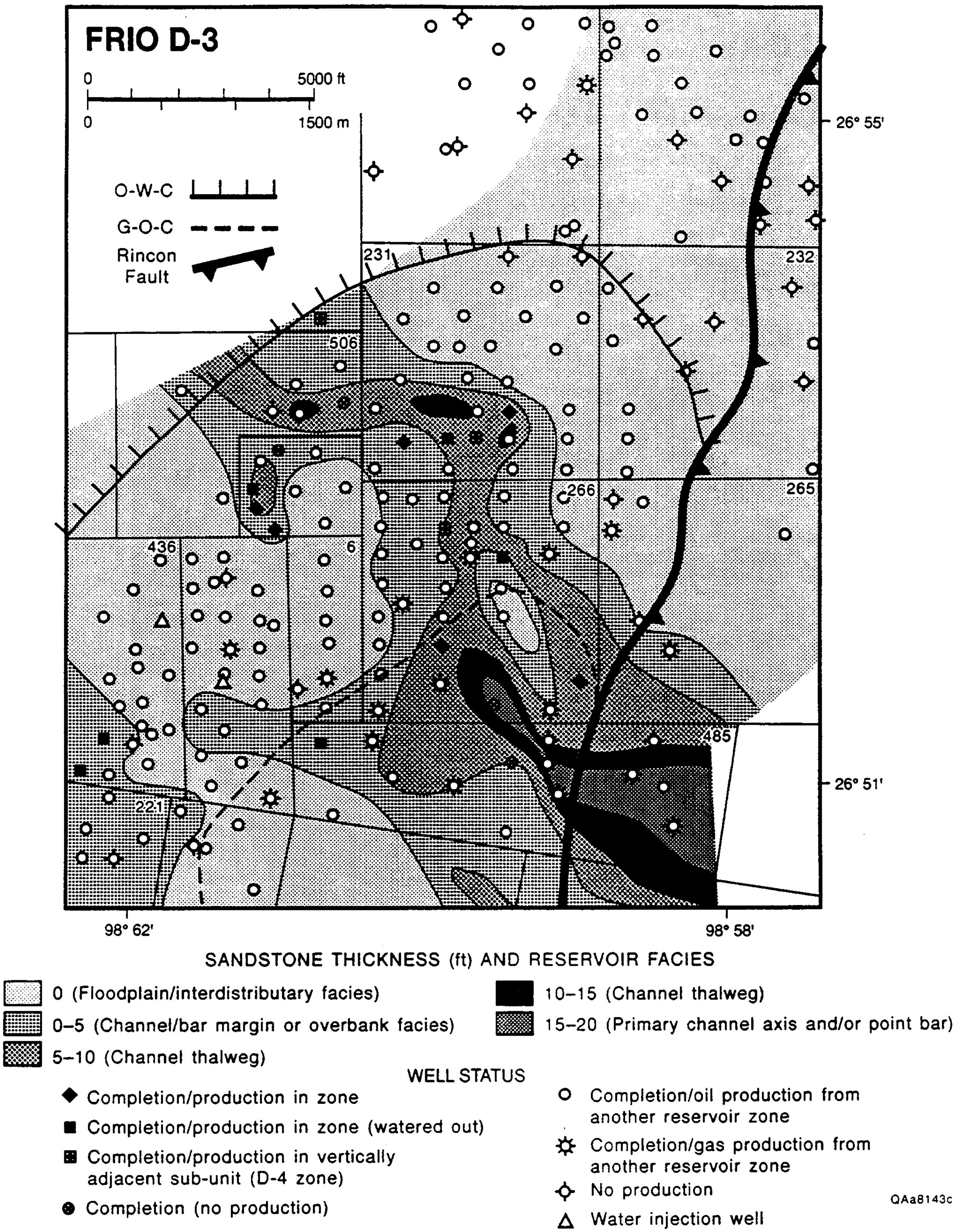

Figure 55. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development in the Frio D-3 reservoir unit.

Table 16: Summary of key reservoir characteristics for the Frio D reservoir zone.

Production summary for Frio D reservoir Zone	D-6	D-5	D-4	D-3
Reservoir sedimentology				
Dominant facies type	Bars/Channel	Mixed	Channels	Channels
Sedimentation style	Progradation	Mixed	Aggradation	Aggradation
Reservoir geometry				
Wells with >0 net sandstone	77	132	127	57
Mean sandstone porosity	19.8	20.5	19.6	18.9
Mean sandstone permeability	49	30	37	14
Max permeability	241	390	199	137
Mean net sandstone thickness	9	13	7	6
Maximum net sandstone thickness	23	24	19	20
Level of development				
Completed zones	14	60	16	22
Producers	/	39	3	10
MBO produced		5866	339	746
Ratio of well completions/ sandstone penetrations	**0.18**	**0.45**	**0.13**	**0.39**

The D-5 reservoir unit is the primary focus of ongoing stratigraphic reservoir studies. As illustrated in Figure 53, the depositional geometry of this 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 all other D reservoir units combined, and production reported for the composite D-4,5,6 reservoir zone totals in excess of 6 MMBO. This complex unit is currently being subdivided into two separate subunits to better elucidate sandstone geometries and identify areas where there may be low permeability facies forming partial or complete barriers that have inhibited or prevented flow communication across the D-5 reservoir. Preliminary assessment of the permeability distribution within the D-5 unit suggests that there are several areas where these 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 (Figure 54). 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. Actual oil volumes produced from the D-4 unit will be allocated after completion of volumetric calculations and petrophysical modeling efforts.

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 (Figure 55). The channel dimensions are relatively narrow in the updip region (2,500 ft) but broaden significantly downdip to the southeast to more than 6,000 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.

Ongoing Project Studies and Strategies for Optimization of Oil Recovery

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 to date on 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 variability in reservoir quality exhibited within these reservoirs are directly responsible for the distribution of original oil in place and have also been primary controls 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. Documentation of stratigraphic heterogeneity and identification of the presence of flow barriers within and between individual Frio D reservoir units are the primary goals of continuing studies to understand styles of reservoir compartmentalization and delineate the location of incompletely drained and undeveloped reservoir compartments. Results from calculations of reservoir areas and volumes for each reservoir subunit will be combined with results from petrophysical modeling of water saturations to generate more accurate original oil-in-place calculations for each of the reservoir units. Cumulative production reported for entire reservoir zones will subsequently be reapportioned to individual reservoir subunits based on the permeability distribution established for each subunit, and these volumes will be subtracted from the OOIP calculations to identify remaining volumes of oil. Areas that contain large volumes of OOIP and little or no cumulative production will represent prospective targets that may contain significant remaining oil.

Engineering studies in progress to estimate drainage radii of productive wells will support stratigraphic studies documenting the geometry of reservoir flow units to identify the locations of remaining mobile oil that will be the targets of incremental recovery. The integration of geological, petrophysical, and production studies will be used to construct maps that will be the key to planning strategies for additional recovery and reserve growth. Maps of porous hydrocarbon volumes will be constructed following petrophysical modeling, and general areas of opportunity will be identified by comparing maps of cumulative production with maps of $S_o \emptyset h$ and remaining oil. Optimum advanced recovery will focus on targeting depositional trends that are coincident with the location of the largest volumes of remaining mobile oil.

T-C-B FIELD RESERVOIR STUDIES

P. R. Knox

Objectives and Methodology

Objectives for the study of Tijerina-Canales-Blucher (T-C-B) field during the second project year included the selection of reservoirs with a high potential for unproduced reserves and the initiation of advanced reservoir characterization studies within these reservoirs to identify untapped and incompletely drained reservoir compartments. Subregional correlation of the T-C-B reservoir interval has provided a framework for the subdivision of the productive interval into 4th-order genetic stratigraphic units. The placement of reservoirs into this framework and subsequent correlation within the field have identified three styles of reservoir architecture. Three reservoir zones, the 21-B, Scott, and Whitehill, each representative of one style, have been targeted for detailed characterization studies on the basis of past production and available data.

Advanced characterization of the three reservoirs is in progress. Reservoir zones have been correlated throughout the field on detailed stratigraphic cross sections, and generalized depositional facies have been determined. The predictive nature of genetic stratigraphy will be applied to the detailed correlation of the sandstones that compose these reservoirs to subdivide the reservoirs and recognize the stratigraphic heterogeneities that compartmentalize these reservoirs. These correlations, and subsequent net sandstone mapping, will establish the three-dimensional distribution of facies and reservoir compartments. Petrophysical analysis using available core, geophysical-well-log, and completion-history information will allow the mapping of porosity and saturation required to calculate reservoir volumes for individual compartments. Comparison of cumulative production on a completion-by-completion basis will be related to compartment distribution to allow apportioning of production to each compartment. This process will identify those reservoir compartments that remain untapped and those that are incompletely drained.

The interpretation of reservoir compartmentalization will be presented to the field operator during the third project year, along with specific recommendations for recompletion and infill drilling opportunities. Technical support will be provided to the operator to evaluate these opportunities and justify drilling or recompletion, as necessary, to confirm the interpretations of this study. Operator action and success based on project findings are recognized as being important to the effectiveness of future technology transfer objectives.

Location and Geologic Setting

Tijerina-Canales-Blucher field is located in the northern half of the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) oil play, about 55 miles southwest of Corpus Christi, and it straddles the border between Kleberg and southern Jim Wells Counties (Figure 56). 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 anticline slightly offset from the crest of the underlying rollover structure.

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 (Figure 9). The location of T-C-B field lies near the boundary of these two depositional systems, and the specific setting of reservoirs varied as the T-C-B area fluctuated between Norias and Gueydan systems throughout the period of Frio deposition.

The area selected for study is within the 3,500-acre "Blucher" lease, located at the southwest edge of the field and operated by Mobil Exploration and Producing, U.S. The Blucher lease represents Mobil's largest lease in T-C-B field and is adjoined by the Blucher "B," A. A. Seeligson, Lobberecht, and Stewart & Jones I and II leases in a contiguous 4,800-acre block. Mobil has supplied well log, core, and production data for more than 80 wells on this lease block.

Reservoir 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

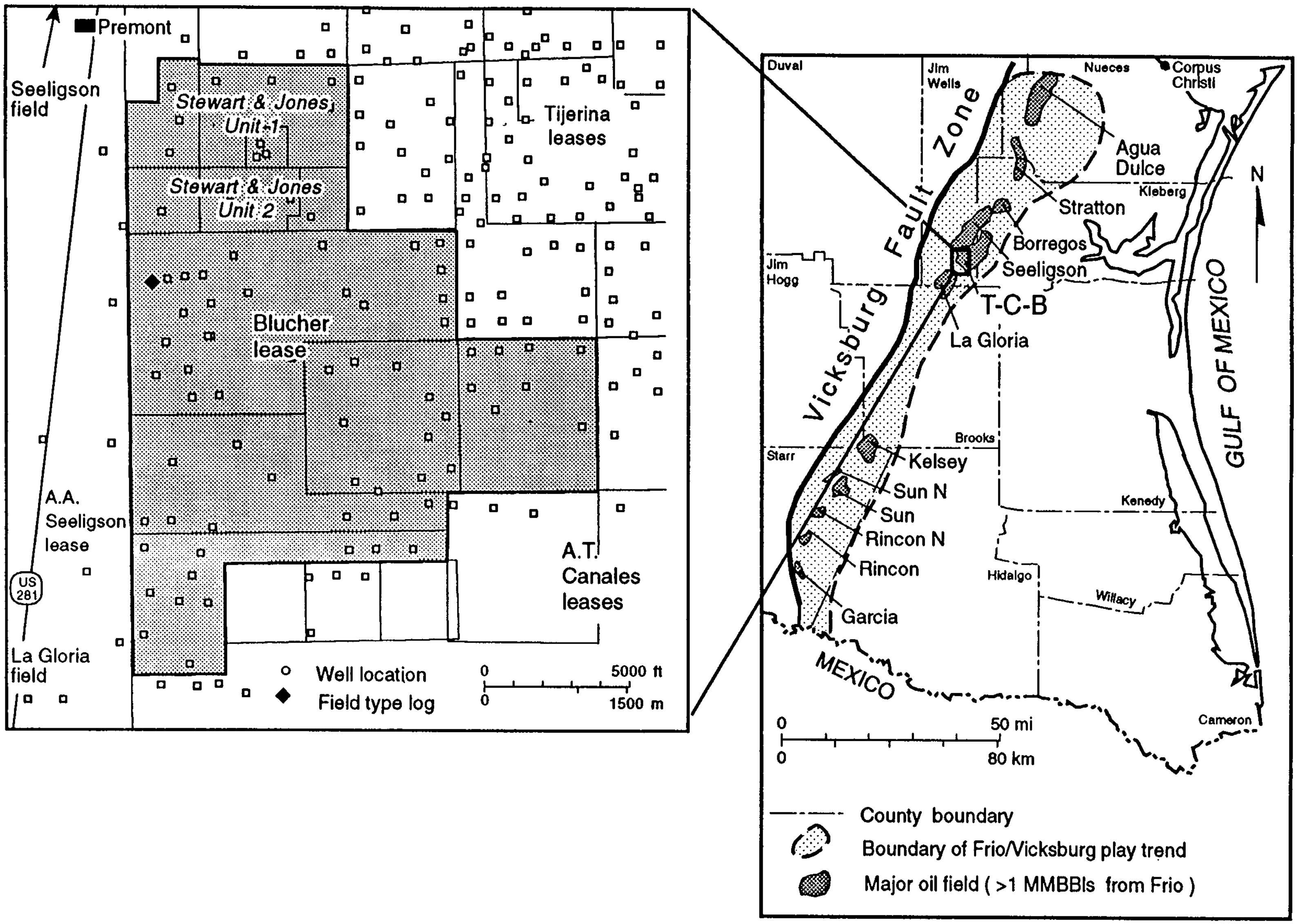

Figure 56. Map showing location of T-C-B field and lease area selected for study.

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. 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, leaving substantial potential for infill drilling opportunities.

Stratigraphic Framework and Preliminary Resource Assessment of T-C-B Reservoirs

General Reservoir Stratigraphy

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 (Figure 57). 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.

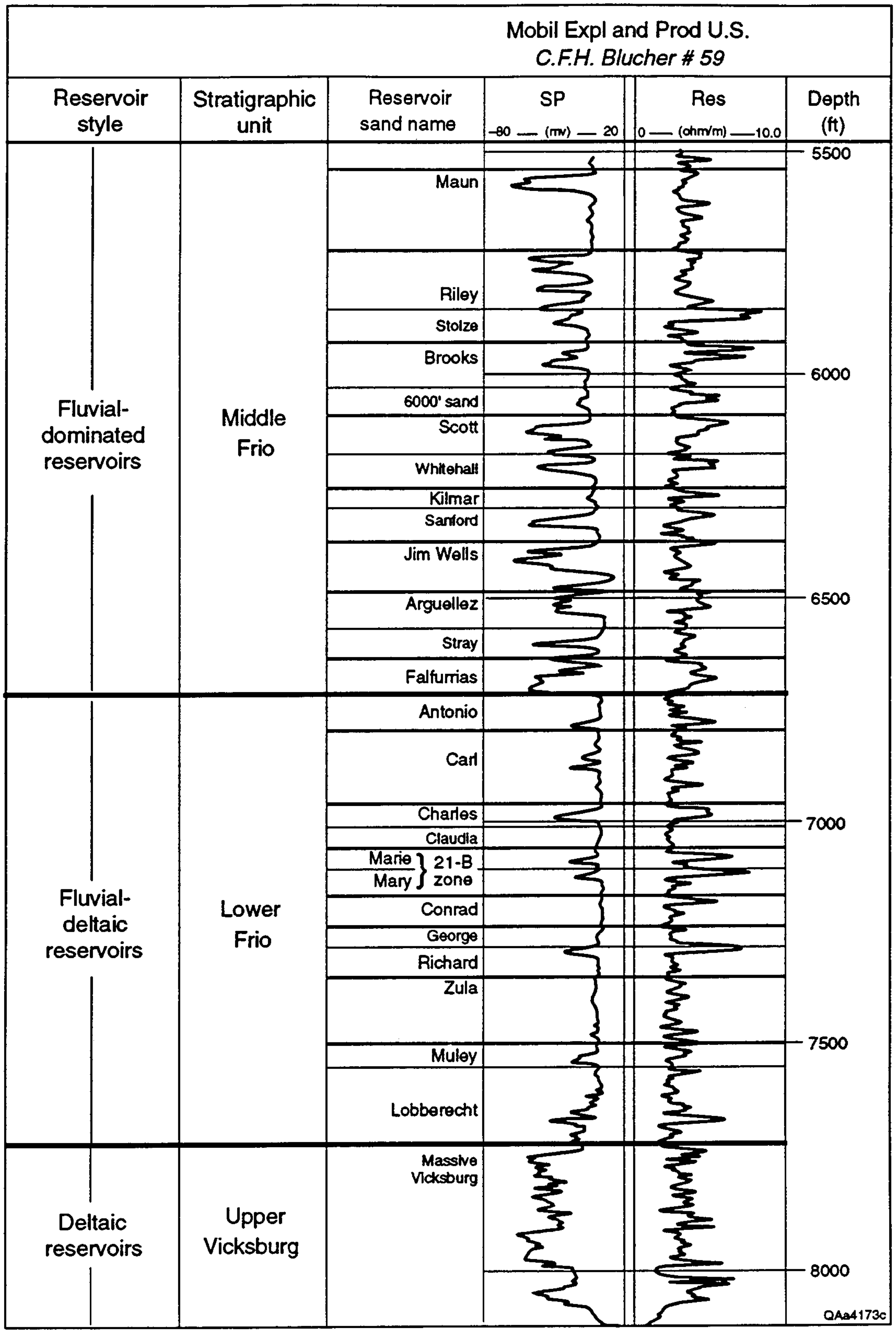

Figure 57. Representative log from T-C-B field illustrating generalized stratigraphy and nomenclature of productive reservoir sandstones.

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 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 (Figure 58) 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. Further study based upon the subregional correlation of the Frio interval will help to identify the boundary between the upper and middle Frio.

Methods

The principal tasks required to identify general reservoir stratigraphy of lower and middle Frio Formation units included (1) placing reservoir zones within a genetic stratigraphic framework through the use of subregional well log correlations, (2) using subregional correlations and genetic framework to evaluate the depositional setting of each reservoir, (3) identifying the general architectural style of reservoirs within a 4th-order genetic stratigraphic unit, and (4) selecting representative reservoirs displaying each of the architectural styles identified. The detailed methodology associated with these processes is described in the following sections.

Identifying the genetic stratigraphic framework

The combined concepts of *depositional sequences* (Mitchum and others, 1977) and *genetic sequences* (Galloway, 1989a) were used to identify packages of rock bounded by stratigraphically

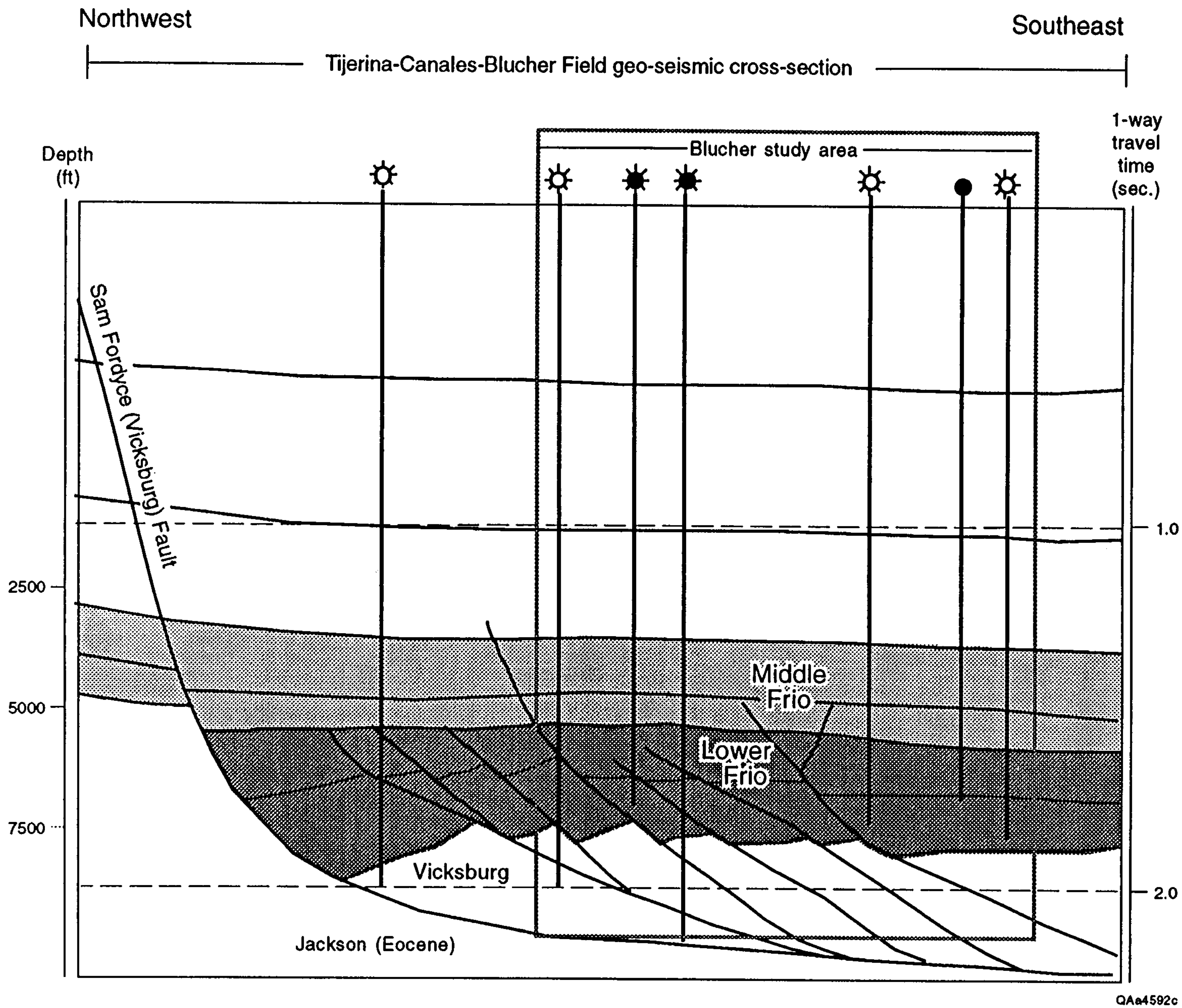

Figure 58. Northwest to southeast geoseismic dip section across T-C-B field illustrating the general structural setting of Frio and Vicksburg reservoir sections. The base of the middle Frio is a significant unconformity separating structurally complicated reservoirs below from less faulted reservoirs above. Seismic interpretation provided by Mobil Exploration and Producing, U. S.

significant surfaces, either unconformities (depositional sequences) or maximum flooding surfaces (genetic sequences). By definition these packages encompass the deposits of a complete cycle of relative sea level or a discrete pulse of sediment input. As a result, they contain a predictable reservoir-scale internal architecture comprising retrogradational-progradational-aggradational or progradational-aggradational-retrogradational subpackages (Figure 59), depending on the convention used. This predictable architecture was used in T-C-B reservoirs to improve the confidence of between-well log correlations, especially in complex depositional settings.

To identify and correlate stratigraphically significant surfaces, a dip-oriented stratigraphic cross section was created that stretches from updip of the T-C-B area to 50 mi downdip, a position that is far enough downdip to tie into the shallow shelf position of individual units within the Frio reservoir interval. This was done because the most readily correlative stratigraphic surface for these units is the maximum flooding surface, which is most evident in the shallow shelf setting. Marine shales blanket the flooding surface during transgression, creating a thin laterally continuous interval that is easily identified in well logs. The most laterally continuous shales bound 4th-order genetic stratigraphic units (GSUs). The 4th-order GSUs were correlated updip to a representative log from T-C-B field. This key log was then used to correlate within the field and identify the 4th-order units in all subsurface data, including well logs and cores.

Fourth-order GSUs within T-C-B field were subdivided into several 5th-order GSUs on the basis of more subtle stratigraphic surfaces. These 5th-order units represent individual reservoirs in some cases. In other cases, however, reservoir zones in T-C-B field are found to contain several 5th-order units. The predictable progradational-aggradational-retrogradational architecture of 5th-order GSUs is being used to more confidently determine the interrelationships of reservoir sandstones that are nearly stratigraphically equivalent but that have been grouped as an individual reservoir by past operators.

Determining depositional setting

To estimate the depositional setting of individual T-C-B reservoirs, the correlative stratigraphic interval was examined in the dip-oriented subregional cross section. Well logs displaying a sandy

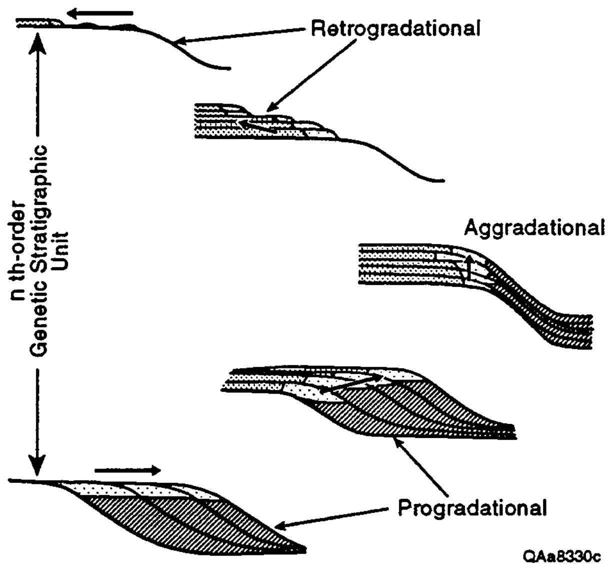

Figure 59. Generalized architecture of a Genetic Stratigraphic Unit illustrating the upward progression from progradational to aggradational to retrogradational stacking of subunits. Genetic Stratigraphic Units are bounded above and below by maximum flooding surfaces. Modified from Galloway (1989a).

upward-coarsening interval of several tens of feet indicate the position of the prograding delta front or shoreface for that horizon, and reservoir sandstones updip of this position have been interpreted to represent deposition in a delta plain setting. The range of log patterns present in the T-C-B reservoir was surveyed to assess the sandstone distribution and likely facies and then assessed in light of depositional interpretations from subregional correlations.

Evaluating architectural style

The general architectural style of the various reservoir zones at T-C-B field has been evaluated. These styles have been grouped into three types, with one representing the spectrum of styles in the lower Frio and two encompassing the range of styles of middle Frio reservoirs.

T-C-B reservoir sandstones were classified as to their lateral and vertical relationship to other sandstones. These relationships describe the architectural style of a reservoir interval and provide insight into the degree of compartmentalization. The evaluation of reservoir architectural style requires a general three-dimensional understanding of the distribution of sandstone bodies within a given reservoir zone. The identification of depositional and genetic stratigraphic setting gained in subregional correlations is fundamental to this understanding. Laterally discontinuous sandstones were identified as stratigraphic equivalents or as elements of a progradational, aggradational, or retrogradational assemblage.

Just as stratigraphic boundaries can compartmentalize a reservoir, so too can structural boundaries. The degree of structural compartmentalization is recognized as varying from the lower Frio to the middle Frio intervals. As a consequence, when evaluating reservoir architectural style, structural style was also assessed.

Selecting reservoirs for detailed study

Reservoir zones were screened to select 4th-order stratigraphic units of each architectural style that represent reservoirs having high reserve-growth potential. The screening process was designed to focus on those reservoirs with high cumulative production, sufficient available data, and a significant level of operator interest. It was reasoned that increasing the recovery from prolific reservoirs will most likely yield larger reserves than a similar level of increased recovery from reservoirs of limited original reserves. In addition, reservoirs of current interest to the operator have a better opportunity to be the targets of recompletion or drilling efforts, providing a tangible test of the methodology used.

Genetic Stratigraphic Framework of T-C-B Field Reservoirs

Within the T-C-B area, a vertical progression of 4th-order units can be identified. Units within the lower Frio are bounded by marine flooding surfaces and range in thickness from slightly more than 100 ft to nearly 200 ft. Units in the middle Frio have either blocky sandstones or upward-fining siltstone and sandstone sequences at their base and range in thickness from approximately 50 ft to nearly 100 ft. These units have been correlated to the stratigraphic terminology of the adjacent Seeligson field (Figure 60) to provide a logical framework for the nomenclature of genetic units and surfaces. Middle Frio reservoirs at T-C-B field are equivalent to the "13" through upper "20" reservoirs at Seeligson. Lower Frio T-C-B reservoirs correspond to lower "20" and "21" reservoirs at Seeligson.

Depositional Systems and Reservoir Attributes

Lower Frio reservoirs

Individual reservoir sandstones within the lower Frio interval, from the 21-B reservoir below to the Antonio reservoir above (Figures 57 and 61), range in thickness from 5 to 25 ft, with the exception of one unnamed sandstone that reaches 50 ft (Figure 61). Sandstones are not laterally continuous. Individual sandstone bodies can be traced in the dip or strike direction for up to one-half mile along lines of cross section and may be coincident with laterally adjacent bodies at the same stratigraphic position. Sharp basal contacts and abrupt upward-coarsening then gradual upward-fining textural profiles have been interpreted from well log data, which, in conjunction with the presence of shallow-shelf and brackish-water microfauna, suggest that sandstones were deposited in distributary-channel and channel-mouth-bar settings in a fluvially dominated delta. Shoreface and tidal-inlet facies interpreted by Reistroffer and Tyler (1991) within the 21-B reservoir in the central part of T-C-B field

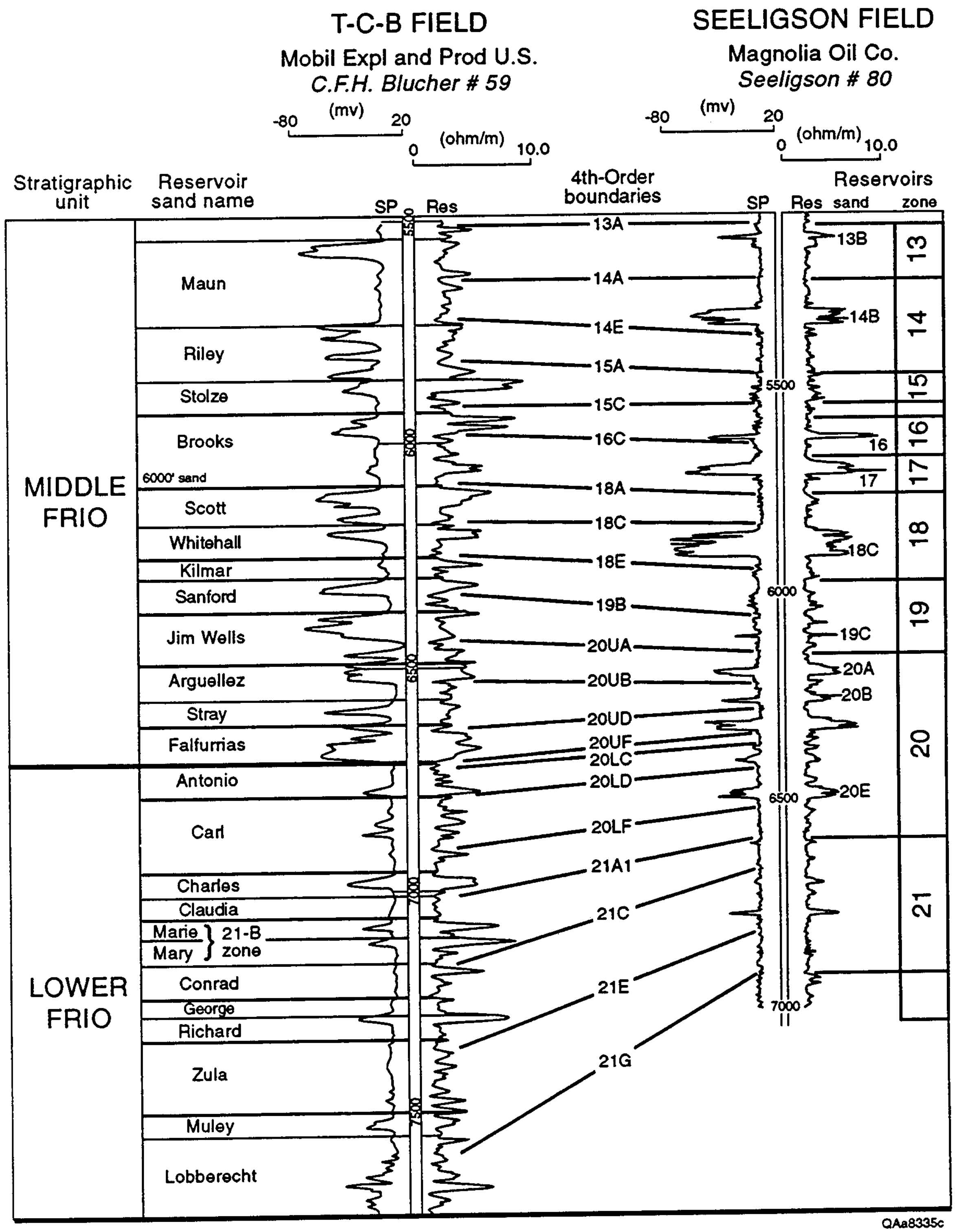

Figure 60. Representative logs from T-C-B and Seeligson fields relating the different reservoir nomenclature to 4th-order genetic stratigraphic unit bounding surfaces. Nomenclature for bounding surfaces is based on the numerical, and consequently more logical, progression used at Seeligson field.

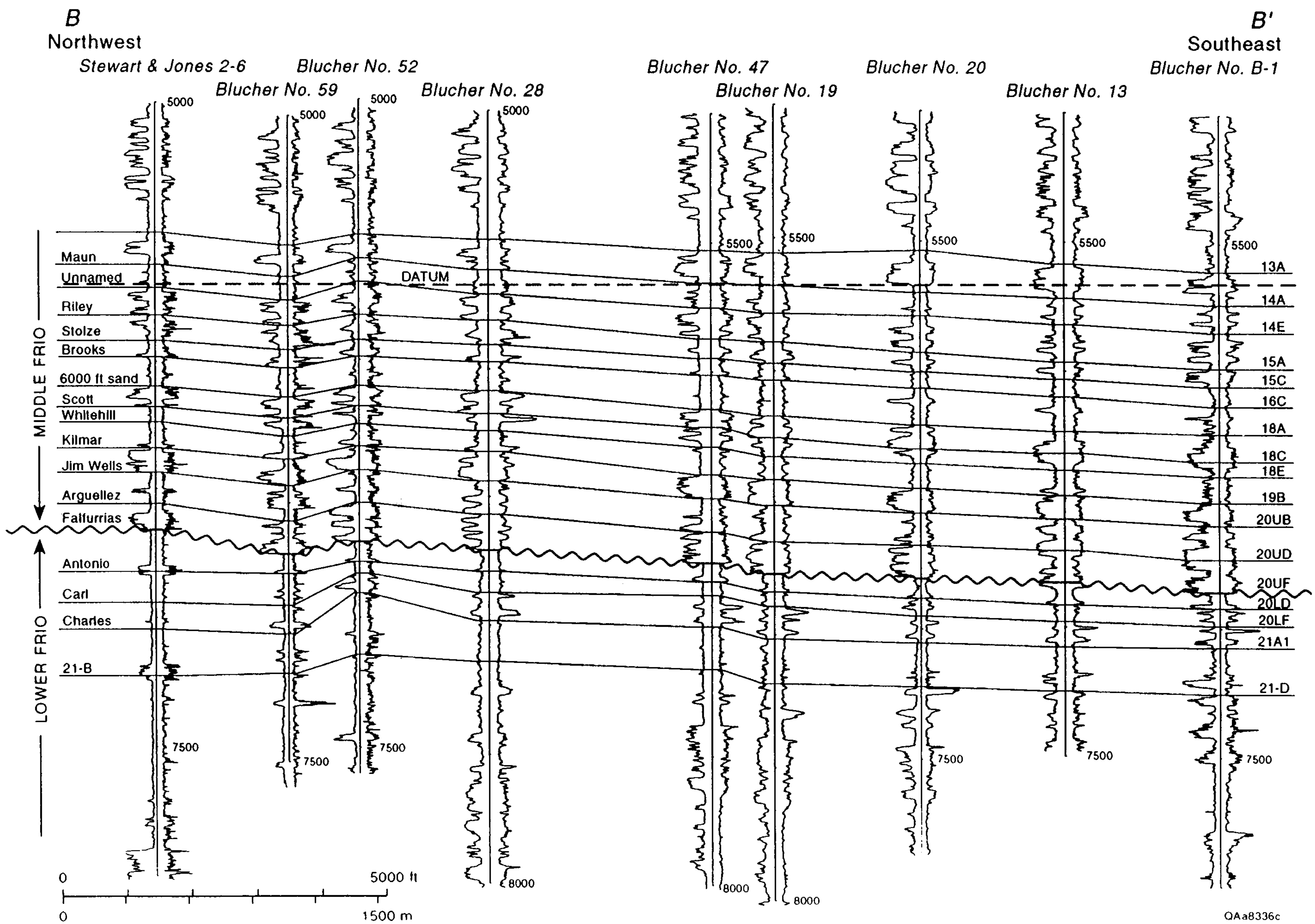

Figure 61. Northwest to southeast dip-oriented cross section through T-C-B field illustrating the lateral continuity and discontinuity of 4th-order genetic units. Note the shale-prone nature of the lower Frio interval and the alternating sandstone- and shale-prone nature of the unconformably overlying middle Frio interval. No faulting has been incorporated.

are consistent with this conclusion and may represent a microtidal barrier/lagoon system that formed to the northeast of a delta distributary system.

The reservoir sandstones of the lower Frio section are separated both laterally and vertically by mudstones deposited in the inner shelf, prodelta, delta plain, and interdistributary bay settings. Thin sandstones and siltstones within mudstones were most likely deposited as splays and levees within interdistributary bays or delta-plain marshes and represent reservoirs with minor potential. An intermittent lack of microfauna in the lower Frio vertical succession indicates that these sediments were deposited on the upper delta plain that was part of the Gueydan fluvial system. Fluctuations in sea level, subsidence, or sediment supply caused repeated southward migration of the boundary between the Gueydan fluvial system and Norias delta system.

The overall pattern demonstrated by paleontological data is an upward decrease in fauna and a complete lack of submarine fauna in the uppermost lower Frio. In addition, the uppermost sandstone in the lower Frio, the Antonio, has an abrupt based upward-fining SP profile and has been interpreted to be in subtly unconformable contact with the units below it (Figure 61). When considered in light of the apparent unconformity at the base of the middle Frio and the upward transition to upper delta-plain facies, we conclude that the lower Frio was deposited in a setting of continually decreasing accommodation indicating persistent progradation.

As illustrated in Figure 58, the lower Frio section is disrupted by several moderate synthetic and antithetic growth faults. Throw on these faults is approximately 50 ft, which is sufficient to isolate the reservoirs on opposing sides of the fault, thereby structurally compartmentalizing some reservoirs. The reservoir quality of these units is very good, with porosities averaging 19 to 25 percent and geometric mean permeabilities from 2 to 77 md (Table 17). Petrophysical analysis of well logs is currently being conducted and log-derived porosities will be compared to values measured from wireline cores. Methods of determining porosity and permeability from core have improved substantially since the 1940's and 1950's, when most of the available core measurements were taken. Thin sections were prepared from sidewall cores for petrographic study to assess the effects of framework mineralogy and diagenesis on porosity and permeability.

Table 17. Summary of geologic and petrophysical characteristics for individual reservoir sandstones in T-C-B field. Revised from McRae and others (1994).

RESERVOIR INTERVAL	Producing Unit	Mean Depth	Depositional Environment and Sandstone Geometry	CORE DATA			POROSITY %		PERMEABILITY	
				wells	feet	N	Mean	s.d.	GeoMean	Median
RILEY	Riley	5874	Vertically Stacked Fluvial Channels	3	15	8	22.1	2.6	26	42
	Stolze	6017	Vertically Stacked Fluvial Channels	2	106	10	21.8	1.9	21	29
BROOKS	Brooks	6144	Vertically Isolated Fluvial Channels	2	60	14	20.3	2.5	7	5
SCOTT	Scott	6137	Vertically Stacked Fluvial Channels	3	102	17	23.0	3.0	3.37	33
	Whitehill	6222	Vertically Isolated Fluvial Channels	1	69	2	24.5	0.6	39	40
KILMAR	Sanford	6320	Vertically Isolated Fluvial Channels	3	31	12	23.6	3.4	10	43
JIM WELLS	Jim Wells	6365	Vertically Stacked Fluvial Channels	2	112	19	22.9	3.1	22	49
ARGUELLEZ	Arguellez	6646	Vertically Stacked Fluvial Channels	5	273	13	21.6	2.9	16	21
	Stray	6793	Vertically Isolated Fluvial Channels	0	0	0	23.5	2.4	5	16
FALFURRIAS	Falfurrias	6812	Vertically Stacked Fluvial Channels	7	156	13	20.7	3.1	7	23
ANTONIO	Antonio	6841	Vertically Isolated Fluvial Channels	4	109	34	20.9	2.3	2	11
CARL	Carl	6961	Vertically Isolated U. Delta Plain	7	56	37	21.6	2.9	65	18
CHARLES	Charles	7003	Vertically Isolated L. Delta Plain	10	238	50	22.0	2.4	9	19
	Claudia	7061	Vertically Isolated L. Delta Plain	2	20	6	19.1	1.1	7	7
MARIE	Marie	7140	Vertically Isolated L. Delta Plain	8	27.5	26	22.6	4.6	31	29
	Corgey	7058	Vertically Isolated L. Delta Plain	1	18.5	6	22.5	2.0	5	26
MARY	Mary	7172	Vertically Isolated L. Delta Plain	8	39	26	25.2	4.8	25	182
CONRAD	Conrad	7224	Vertically Isolated L. Delta Plain	11	150	88	24.6	3.7	77	106
RICHARD	Richard	7280	Vertically Isolated L. Delta Plain	7	57.5	34	24.5	3.2	20	86
	George	7290	Vertically Isolated L. Delta Plain	4	11.5	21	20.7	3.4	7	5
ZULA	Zula	7308	Vertically Isolated Delta Front	5	35.5	16	23.4	2.7	12	43
LOBBERECHT	Lobberecht	7379	Vertically Isolated Delta Front	6	135	32	25.2	4.7	57	168
VICKSBURG	Massive Vicksburg	7493	Vertically Stacked Delta Front	6	114	12	21.1	3.3	2	15

Middle Frio reservoirs

Reservoir sandstones within the sand-dominated middle Frio interval include the Riley to Falfurrias zones (Figures 57 and 61); they occur as laterally continuous to discontinuous upward-fining packages ranging in thickness from 5 to 30 ft that commonly stack into units up to 90 ft thick. Laterally and vertically adjacent shaly sections contain thin spiky to upward-fining sandstone beds and upward-coarsening siltstone beds. These patterns, combined with a lack of marine microfauna and a sandstone-to-total-rock ratio of approximately 40 percent, indicate that these sediments were most likely deposited in a mixed-load fluvial channel system, probably in an upper delta-plain setting. Thicker upward-fining sandstones were deposited most likely as point bars in a meandering channel, and thin sandstones and upward-coarsening siltstones and fine sandstones were deposited as splays on the upper delta plain.

The middle Frio interval at T-C-B can be subdivided into sandstone-rich and sandstone-poor packages ranging in thickness from 70 to 110 ft (Figure 61). Sandstone-rich intervals contain channel sandstones up to 20 ft thick that are laterally isolated from stratigraphically equivalent channels by floodplain mudstones but are commonly in contact with vertically adjacent channel deposits. Scour surfaces between stacked mixed-load channel sandstones observed in outcrop are commonly overlain by thin mudclast-rich intervals that have dramatically reduced permeability (Fisher and others, 1993). Sandstone-poor intervals in the middle Frio Formation contain similar channel sandstones that are laterally isolated from equivalent channels by floodplain mudstones. However, these channels are also vertically isolated from any overlying channels by at least 5 ft and commonly up to 50 ft of mudstone.

Reservoirs within the middle Frio section have reservoir quality similar to that of lower Frio zones (Table 17), despite their slightly shallower burial depth and more proximal setting. Average porosities for reservoir zones measured from wireline cores range from 20 to 24 percent, and permeabilities range from less than 10 md to nearly 40 md. One explanation for the lower than expected porosity and permeability of these units comes from observations of middle Frio reservoirs in the Stratton and Seeligson fields of South Texas. Kerr and others (1992) noted the presence of abundant volcanic glass in this stratigraphic interval, and Grigsby and Kerr (1993) document a decrease in reservoir quality owing to clay precipitation related to diagenesis of the volcanic rock fragments.

The middle Frio interval is largely undisturbed by faulting, instead being folded into a broad anticlinal feature. A dip-oriented seismic line (Figure 58) contains minor disruptions at this level that may be discrete faults with less than 30 ft of displacement or may be steep folds over deeper faults.

Implications of Reservoir Stratigraphy on Hydrocarbon Production and Reservoir Heterogeneity

The architecture and resulting interrelationship of sand bodies in the lower and middle Frio strongly control reservoir heterogeneity and hydrocarbon production behavior of each reservoir zone. All reservoirs within the lower and middle Frio can be grouped into three styles on the basis of the architecture of their sandstone bodies. One style is unique to the lower Frio, whereas middle Frio reservoirs display two additional styles.

As mentioned, lower Frio reservoir sandstones are discontinuous over the study area but commonly overlap one another vertically. Where they are vertically stacked they are separated by at least 5 ft of shallow marine or lower delta-plain mudstone, which forms an excellent seal and isolates individual sandstones. Thus, lateral facies changes are the primary stratigraphic control on reservoir compartment boundaries. However, significant structural controls on compartmentalization also exist. The rocks of the lower Frio interval are broken by faults that are both synthetical and antithetical to the major bounding growth fault, the Sam Fordyce fault (Figure 58). As a result, the field is divided into strike-elongate blocks. These blocks lie parallel to delta-front and shoreface sandstone bodies and, as a result, have a subdued effect on compartmentalization. However, these faults lie perpendicular to dip-oriented distributary channel sandstones, isolating them into short, narrow segments and creating compartments of limited extent. We have defined this reservoir architecture style as *vertically isolated and structurally complicated.*

Reservoir compartment styles in the middle Frio have been separated into two categories. These include the *vertically stacked, laterally isolated* style of the sand-rich intervals and the *vertically and laterally isolated* style of the sand-poor intervals (Figure 62). Compartmentalization in the vertically and laterally isolated style will be more straightforward in its identification because compartment boundaries are clearly limited by channel and splay margins. This style of reservoir may also contain the potential for stratigraphically trapped accumulations located off the crest of the structure due to the presence of narrow sinuous channel sandstones that form arcuate concave-updip sandstones.

The variable nature of boundaries in vertically stacked, laterally isolated compartments complicates the identification of untapped and incompletely drained reservoir bodies. This is due to the fact that low-permeability mudclast-rich layers at the base of channels may present complete or only partial seals between channel sandstones. A more thorough reservoir engineering approach will be required to evaluate the reserve status of compartments identified by geologic methods.

Identification of Reservoirs with High Potential for Incremental Oil Recovery

21-B zone sandstones

We consider the 21-B zone, which includes the Mary and Marie sandstones and their stratigraphic equivalents, to contain the highest potential for incremental oil recovery of all reservoirs in the lower Frio Formation at T-C-B field. This interval has produced over 500 MSTB of oil from the Blucher area from more than 40 completions (some vertically stacked within a single well) since 1945 and is the most prolific reservoir in the T-C-B area. Figures 63 and 64 show the number of completions active over this period and the location of productive wells. An increasing number of completions were active from the late 1940's through the mid-1970's. Following this period, a large number of completions were abandoned, presumably because declining production and rising commodities prices resulted in more economical completions in up-hole reservoirs. This trend has accelerated in the early 1990's. However, increasing interest in deeper, structurally complex reservoirs caused by new seismic technology will result in new well bores that penetrate this interval and provide recompletion opportunities. It is hoped that reservoir compartmentalization in the 21-B zone identified in this study will be used as partial criteria in the selection of locations for future wells targeting deeper objectives.

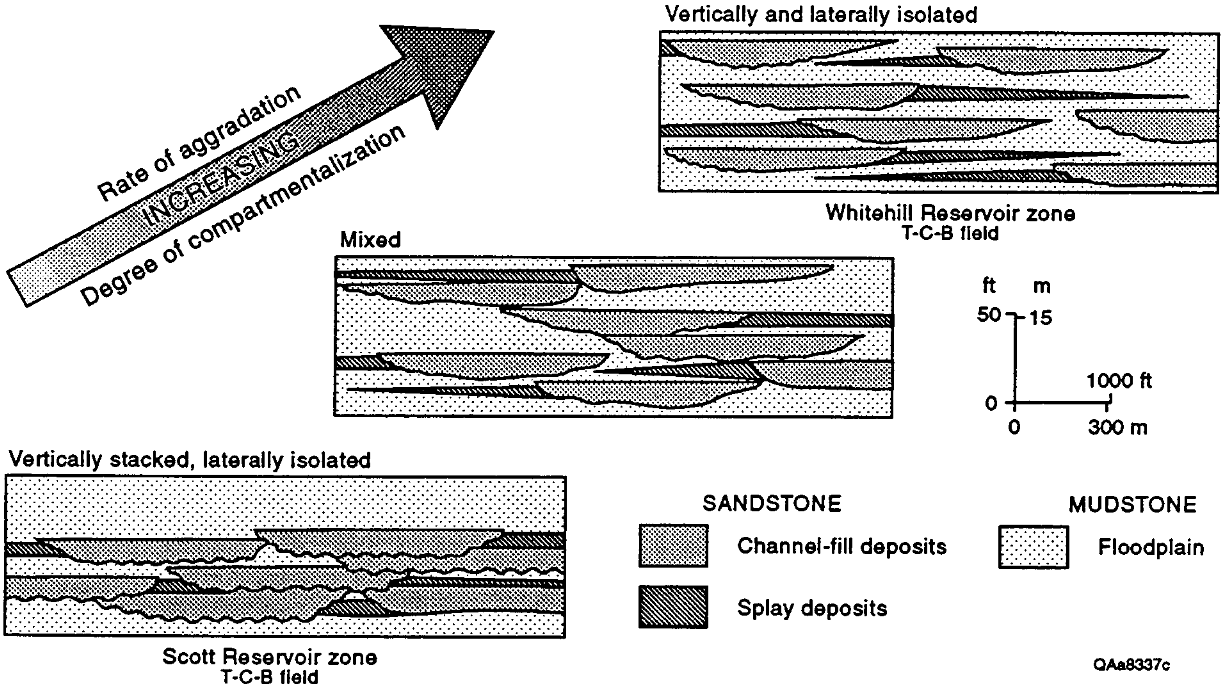

Figure 62. Continuum of fluvial (upper delta plain) architecture of the middle Frio Formation first recognized in Seeligson and Stratton fields of South Texas by Kerr and others (1992). Reservoirs in T-C-B field also exhibit these architectural styles. One end of the continuum is represented by the Scott zone in T-C-B field, and contains laterally adjacent stratigraphically equivalent channel deposits that are isolated by intervening floodplain mudstones, but are in contact with vertically successive channel deposits. The other end of the continuum is represented by the Whitehill zone, which contains channel sandstones that are laterally and vertically isolated from other channel deposits by at least several feet of floodplain mudstones. This architecture is controlled by rates of aggradation and proximity to major fluvial axes.

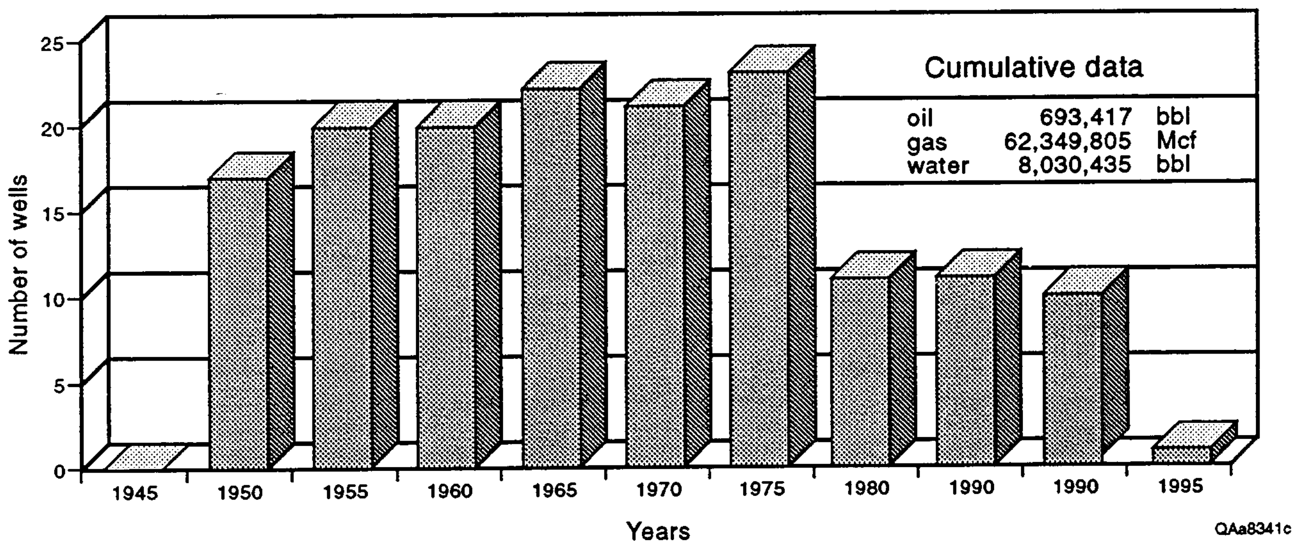

Figure 63. Number of active completions per 5-year time block, starting in 1940-1945, and cumulative production for 21-B Zone reservoirs within Mobil's contiguous acreage block of T-C-B field. All productive reservoirs of approximate stratigraphic equivalence to the 21-B have been summed for this diagram, and include the 21-B, 21-B4 West, Marie, Mary, Corgey 7000, Corgey West, Margaret, and Helen. The drastic decline in activity in the 21-B zone since 1975 and the current minimal number of completions show that this zone is in a mature stage.

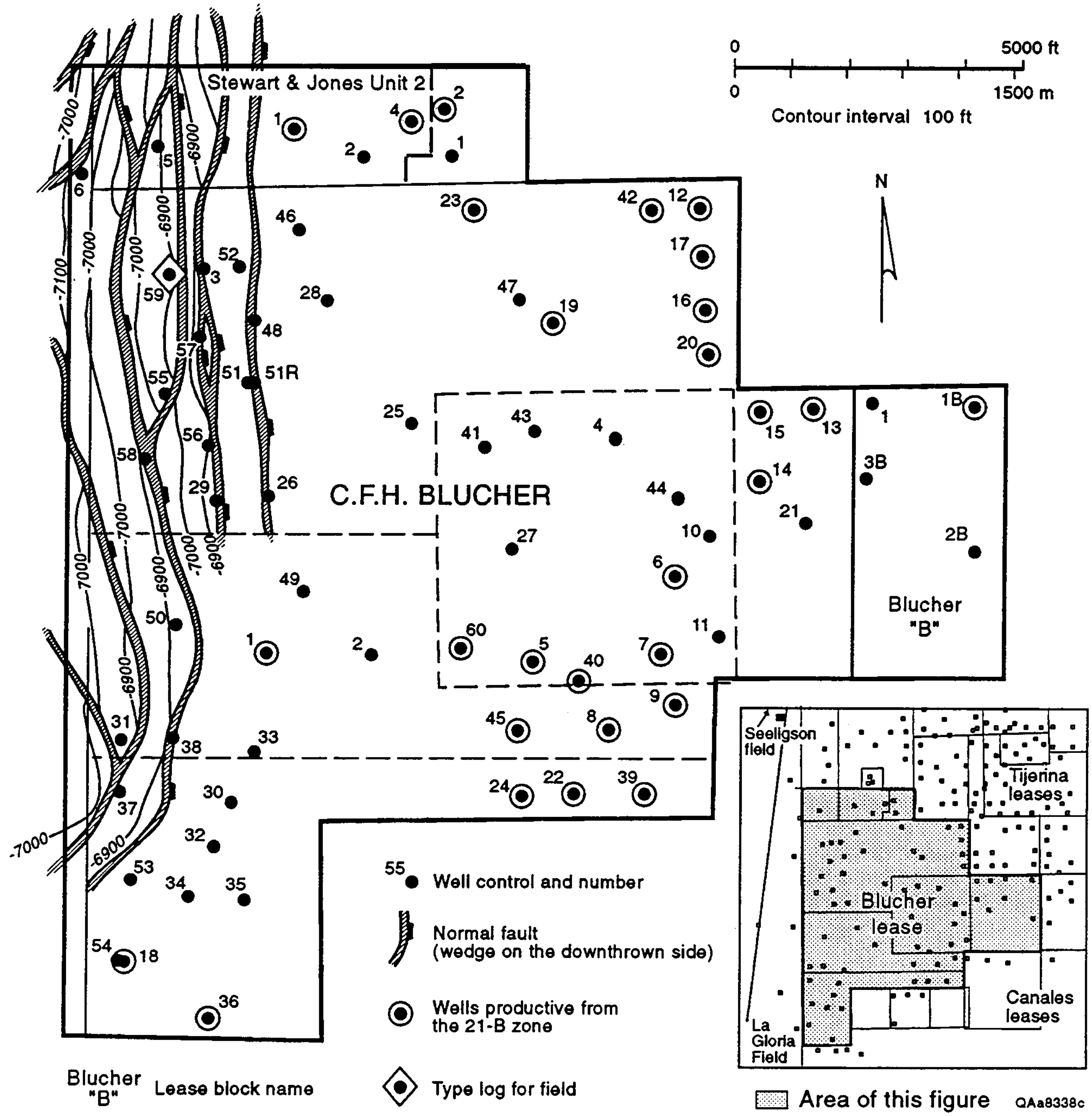

Figure 64. Map of Blucher lease showing wells productive from the 21-B zone and illustrating the structural complexity of a portion of the productive area. Structural interpretation of the western portion of Blucher lease was provided by Mobil Exploration and Production U. S. and is based on well and two-dimensional seismic data. The interpretation for the remainder of the area is not shown.

The 4th-order GSU containing the 21-B zone has been selected for detailed study because of this potential and because it represents an excellent example of the laterally isolated, structurally complicated reservoir architecture style common throughout the lower Frio. A preliminary assessment indicates that several thin reservoirs, including the Mary, Marie, Margaret, Corgey, and Corgey West, lie within a narrow stratigraphic interval that local operators refer to as the 21-B zone. The upper units in this succession appear to be arranged in a generally retrogradational architecture similar to that observed by Reistroffer and Tyler (1991). Individual reservoir names have been applied to locally developed sandstone bodies. We anticipate identifying both dip- and strike-elongate reservoirs within this succession because it should contain both the progradational/aggradational 5th-order GSUs that most likely reflect deposition in a fluvially dominated delta and the retrogradational 5th-order GSUs that were more likely deposited in a strongly wave modified fluvially dominated delta system.

Faulting is present within the 21-B Zone interval, which will complicate the identification of compartment boundaries. This problem cannot be avoided in any of the reservoirs within T-C-B that were deposited in a delta-front and lower delta-plain setting. Structure maps of a portion of this interval based on two-dimensional seismic data have been provided by the operator (Figure 64) and will be used to define the structural contribution to compartmentalization. In addition, three-dimensional seismic was recently acquired over a portion of the Blucher area, and an interpretation based on this data may be made available to us by the operator before final recommendations on specific opportunities are made.

Scott and Whitehill sandstones

The Scott and Whitehill zones are interpreted as vertically adjacent 4th-order GSUs in the middle Frio, and together they represent the most prolific reservoirs within this interval. Over 100 MSTB has been produced from the combined zones in a total of at least nine completions starting as early as 1945. Eight completions have produced from the Scott zone (Figures 65 and 66), whereas at least one and probably as many as three wells have produced from the Whitehill. Figures 65 and 66 show the number of completions active over this period and the location of productive wells. Many of these completions are in wells drilled in the late 1980's as infill wells targeted specifically at the Scott,

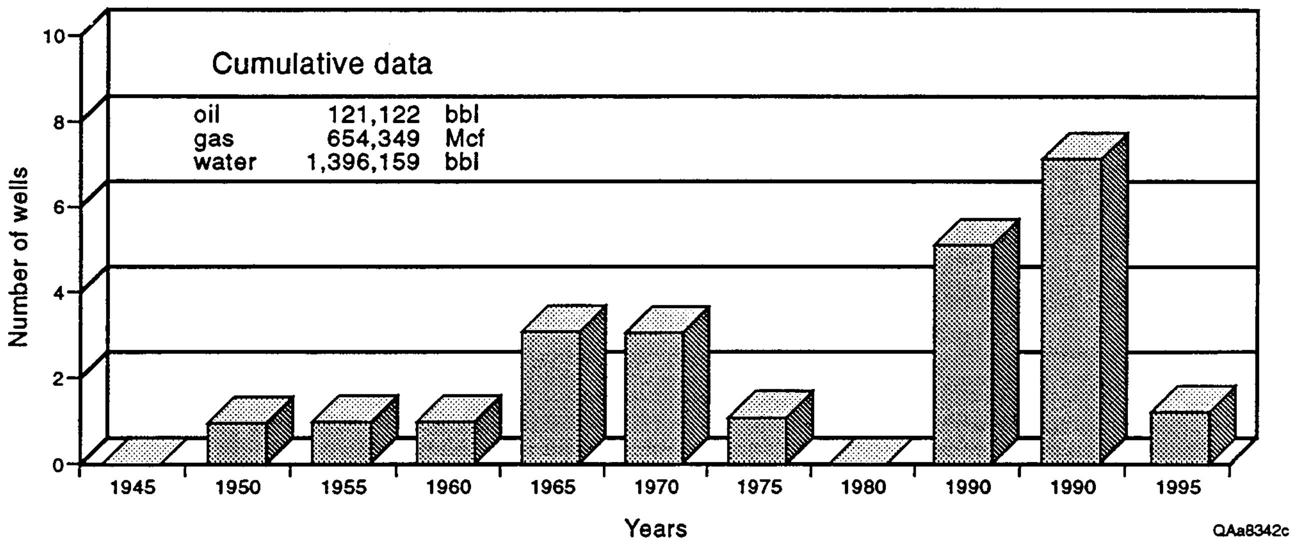

Figure 65. Number of active completions per 5-year time block, starting in 1940-1945, and cumulative production for Scott and Whitehill reservoirs within Mobil's contiguous acreage block of T-C-B field. Note the increase in activity during the 1980's as the operator focused on up-hole objectives, and the declining number of completions in the 1990's as initial completions matured.

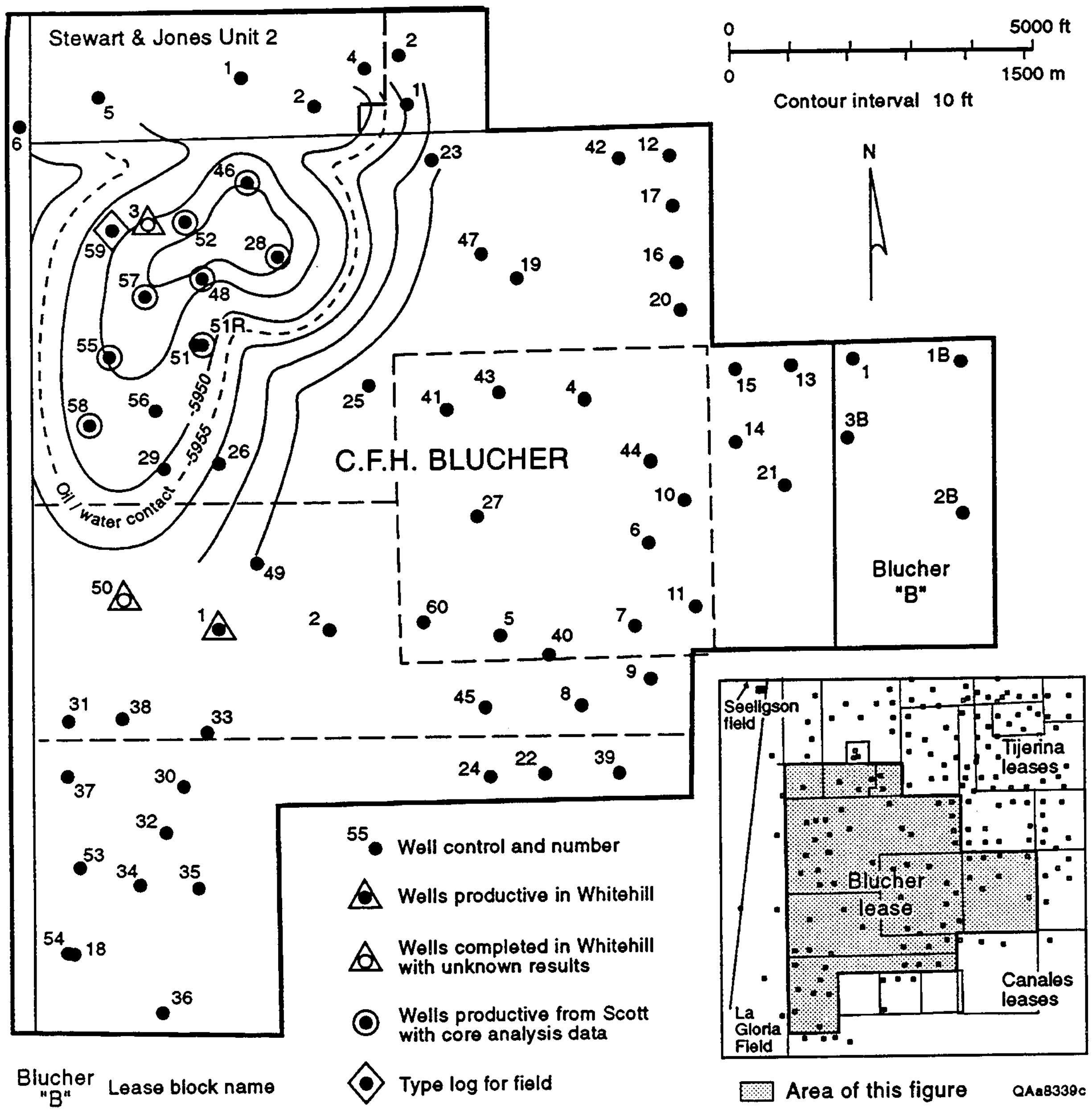

Figure 66. Map of Blucher lease showing wells productive or possibly productive from the Scott and Whitehill zones of T-C-B field. Structural entrapment of hydrocarbons is the result of a gentle north-south oriented anticline in the northwest part of the lease. Structural interpretation was provided by Mobil Exploration and Production, U. S. Contours for the remainder of the lease are not shown.

showing the operator's recent interest in this zone. Despite a long production history and recent focused attention, the Scott has produced less than 5 percent of the original oil in place, as calculated from operator-supplied maps and petrophysical parameters. Undoubtedly, extensive unrecognized reservoir compartmentalization has contributed to low recoveries.

The Scott zone exemplifies the vertically stacked, laterally isolated architectural style whereas the Whitehill contains reservoirs best described by the vertically and laterally isolated style. Both reservoirs have been selected for detailed study because of their high cumulative production and because the individual sandstones will represent an important continuum of transition from one style to the other. These reservoirs are essentially unfaulted, with hydrocarbon entrapment resulting from a north-south striking anticline in the northwest portion of the Blucher lease (Figure 66).

Characterization of Reservoir Heterogeneity

The characterization of reservoir heterogeneity in the reservoirs selected for detailed study has focused on log-to-log correlation and mapping of individual sandstone bodies that were deposited within the delta-front and delta-plain settings. The detailed correlation necessary in these complexly interbedded sandstones has required the use of dip-oriented 1 inch = 20 ft-scale looped cross sections, enabling the correlation of subtle surfaces from either end of a section to the middle. This looped style of cross sections speeds the correlation process and adds confidence to the interpretation. Correlations within the first loop are tied to a single key well, and each successive loop section shares a side with a previously interpreted section, reducing uncertainty in correlation within the succeeding dip section.

Groups of such sections have been established and correlated for the 21-B and Scott/Whitehill intervals. Only wells with original 1 inch = 20 ft-scale logs were used for these detailed sections. Wells not on the cross sections, and those having only 1 inch = 50 ft- or 1 inch = 100 ft-scale logs, will next be correlated with compartments identified on the cross sections. Available routine core analysis data from wireline cores and porosity data from geophysical logs will be used to determine the petrophysical nature of facies and intrafacies boundaries to make preliminary evaluation of the competency of these surfaces as barriers or baffles to fluid migration. These contacts, which represent boundaries between various facies within a 5th-order unit and boundaries between individual sandstone bodies, will then be used to measure and map net sandstone thickness for individual reservoir compartments. Adjacent channels that are in sandstone-on-sandstone contact will be mapped as separate compartments, and available engineering data will later be applied to assess intercompartment communication.

Delineation of Additional Mobile Oil

Methodology and Progress to Date

The first and most time-intensive step of developing a petrophysical model, that of obtaining digitized values from the paper copies of logs, has been completed. Computer-based log analysis in mature fields is hampered by the lack of data in digital form. Well logs for this project were digitized using an advanced interactive digitizing software that allows quicker and more accurate capturing of log digits.

When compartment boundaries are confirmed and the compartment net sand volumes mapped, volumetric analysis will determine the volume and residency of remaining mobile oil. This process includes the steps of developing a petrophysical model that accurately identifies porosity and saturation from logs, calculating original reserves through volumetric analysis, and identifying past production on a compartment-by-compartment basis. Past production is then subtracted from original reserves to determine the remaining mobile oil in each compartment.

Developing a Petrophysical Model

The key parameters for volumetric analysis, porosity, and oil saturation will be determined from computer-based analysis of geophysical well logs. Porosities calculated from the available sonic and density-neutron logs will be quantitatively compared to porosity measurements from wireline cores to develop a refined porosity model. Analysis of porosity logs will be assisted by petrographic analyses of framework mineralogy. This porosity model will then be cross correlated with SP and/or resistivity measurements in the same wells used to develop the model. This correlation will allow a prediction of porosities in wells that do not have log-derived porosity measurements. This predictive porosity model will then be used in conjunction with resistivity values to calculate oil saturations. Calculated values will be qualitatively compared to known well response and production history to iteratively refine a saturation model. This process will produce an algorithm that will allow the most accurate calculation possible of porosity and saturation in all wells throughout the field.

Porosities and saturations calculated from the model will be mapped using the facies and net sandstone maps as a framework. Porosity (Ø), oil saturation (S_o), and reserve potential ($S_o Øh$) maps will be used to calculate reservoir compartment volumes. Total and residual oil saturations will be applied to these values to calculate original mobile oil-in-place volumes.

Identifying Past Production

A critical step in identifying untapped and incompletely drained reservoir compartments is the process of determining the past production history of a reservoir and its various compartments. Unless production from several zones has been commingled within the well bore, production information on a completion-by-completion basis is usually, though not always readily, available. This information is available for T-C-B reservoirs. Unfortunately, detailed monthly production information for T-C-B reservoirs prior to 1967 was never given to the present operator when they purchased the field from the previous operator in 1967 (McRae and others, 1994). However, some cumulative production by well and zone prior to 1967 exists, and the operator has made available their calculations of monthly well-by-well production since 1967. These data have been placed into a computerized data base and will allow an evaluation of past production on a compartment-by-compartment basis.

Decline analysis using detailed production and pressure data has been used by other workers (Lord and Collins, 1992) in gas fields within this play to assess possible leaky seals between compartments. It was hoped that sufficient oil production data would be available for T-C-B to allow a similar assessment. Unfortunately, oil production data were not measured on a separate flowline for each well but instead were apportioned from annual test rates and total lease production. As a consequence, many oil-production decline curves show artificial-appearing production histories and only sporadic water production (Figure 67), indicating a data set of questionable value for decline analysis. However, gas production data have been more closely monitored. Monthly production

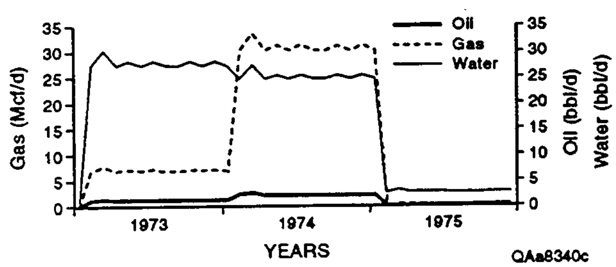

Figure 67. Representative monthly production curve for a completion within the Scott interval of Blucher 46, T-C-B field. Note the abrupt rise and fall of production rates, possibly due to erratic yearly flow tests used to apportion lease production to this completion. Data such as these are of questionable value for decline curve analysis.

values and recorded shut-in periods may provide the data necessary to evaluate partially leaky compartment boundaries. A computer-based model created as a result of a joint DOE-Gas Research Institute funded project (Lord and Collins, 1992) can use gas production and pressure data to calculate the permeability of leaky compartment boundaries.

Mass Balance Calculations

The information determined in the calculation of original reserves and gathering of past production history will be used to identify untapped and incompletely drained compartments. Original mobile oil reserves will be calculated for each compartment. Production records will be examined to identify any wells that were completed within the compartment being assessed. If a given compartment has been completed, the cumulative volume produced will be compared to the original in-place volume calculated.

The histories of wells completed in compartments where past production is significantly less than calculated reserves will be examined for indications of a mechanical or other failure that caused premature abandonment of the wells. Lacking such evidence, the geologic model will be reassessed to attempt to locate unrecognized internal boundaries that might have subdivided the compartment. External compartment boundaries will also be reevaluated for alternate geologic interpretations that might define a compartment of the size indicated by production data.

In cases where production substantially exceeds original calculated reserves, geologically determined compartment boundaries will also be reevaluated. Not only will the size and shape of interpreted compartments be examined, but compartment boundaries will also be scrutinized for potential sandstone-on-sandstone contacts. Such contacts would create the potential for cross-compartment drainage. Adjacent compartments that are interpreted as being untapped on the basis of production histories may have contributed to the unexpectedly high production of a given compartment across intervening leaky seals.

PLANNED ACTIVITIES

Completion of Phase II Activities

A significant amount of work is currently in progress that will be completed by the end of Phase II, which is scheduled for completion at the end of calendar year 1994. Tasks in progress as part of Phase II studies are focusing on delineation of incremental recovery opportunities of selected reservoir zones in Rincon and T-C-B fields.

Rincon Field Reservoir Studies

The development of petrophysical models to calculate porosity, permeability, and water saturation in Rincon field reservoirs is presently underway in wells with core data, to take full advantage of existing porosity and permeability data and results from special core analyses and petrographic examination. Results from petrographic work and special core analyses on Rincon cores will be available in the near future. The results from these analyses will be keyed to petrographic studies from the same sample, and the combination of this analytical work will provide a good petrophysical data set on these reservoirs. Following petrophysical studies of target reservoir intervals in each field area, initial oil-in-place volumes will be calculated and known production subtracted to determine the remaining volume of reserves. Through this process, untapped and incompletely drained compartments will be identified. Simulation of petrophysical attributes using 3-D computer visualization will be pursued to document internal geometry and heterogeneity within a selected reservoir zone. These results will lead to an understanding of reservoir flow-unit boundaries, their control on oil production, and the identification of untapped and incompletely drained zones that may be targeted for incremental recovery by recompletions and strategic infill drilling.

T-C-B Field Reservoir Studies

Tasks remaining in the delineation and documentation of untapped and incompletely reservoir compartments drained reservoirs in T-C-B field include final mapping of compartments, petrophysical analysis, volumetric analysis, and preparation of text and figures supporting our conclusions. Final mapping of reservoir compartments will involve (1) correlating facies and compartment boundaries to wells other than those on detailed loop cross sections, (2) using available porosity and permeability data to characterize the petrophysical nature of facies and compartment boundaries, and (3) determining and mapping facies and net sandstone thickness for individual reservoir compartments. Compartment boundaries identified in the 21-B zone may be modified later in the year through contact with the operator in light of recently acquired 3-D seismic that will be interpreted during the third project year.

Detailed petrophysical analysis during the third project year will use logs digitized during the second year to develop a predictive porosity model. We will then cross correlate this model with measured SP and/or resistivity values to create a porosity-to-log relationship usable throughout the field. This porosity relationship will allow calculation of saturations throughout the field. Porosity and saturation calculations will be evaluated in light of other available information such as routine core analysis and well performance. Porosity and saturation information will be mapped, and maps will be digitized to allow accurate calculation of original in-place reserves. Production tabulated on a completion-by-completion basis will be compared to original in-place reserves. Any discrepancies indicating over drainage or incomplete drainage will prompt a reevaluation of the geological interpretation to ensure that compartment boundaries are valid. Remaining discrepancies will then be used to document untapped or incompletely drained compartments.

Following completion of petrophysical analysis, net-sandstone, net-pay, and $S_o Øh$ maps will be constructed. In addition, reservoir production behavior in the various facies and architecture styles will be evaluated. Petrographic analysis of selected samples may reveal any mineralogic or pore-type differences between reservoir zones or adjacent facies within zones that control production behavior. Analysis of production decline curves of individual completions may also assist in identifying behavior characteristic of architecture styles and individual facies. Volumetric estimates of produced fluids and remaining reserves in selected reservoirs in both fields will be calculated to identify and delineate the additional resource potential residing in incompletely drained and untapped reservoir compartments.

Phase III Project Description and 1995 Activities

The goals of Phase III of this project are technology transfer, definition of extrapolation potential, and development of a computer-based "advisor." The first year of Phase III (Budget Period 2) covers calendar year 1995, when five tasks are scheduled to be initiated.

Task 1 covers documentation of the distribution of untapped reservoirs for technology transfer. This task is scheduled to begin on January 1, 1995, and to take seven months to complete. The goal of the task is to document results of untapped reservoir analysis and to prepare documentation for reports and technology transfer workshops. Presentation of results will be made at local and national meetings of appropriate geologic and petroleum engineering societies.

Task 2 is parallel to, and runs concurrently with, Task 1. The goal is to document results of incompletely drained/compartmentalized reservoir analysis and to prepare documentation for technical papers and technology transfer workshops. Similarly, Task 3 will be used to document results of new pool reservoir analysis and to prepare documentation for reports and technology transfer workshops. This effort is likely to be more limited in scope than Tasks 1 and 2, given the lesser project emphasis on this resource type.

Also in 1995, the results of Tasks 1, 2, and 3 of Phase II (delineation of untapped, incompletely drained/compartmentalized, and new pool reservoirs) are scheduled to be summarized in a topical report. Previous reporting schedules have indicated that this topical report would be completed June 1, 1995. We recommend that the date of this topical report be shifted to August 1, 1995, in order to benefit from the completion of Phase III documentation tasks 1, 2, and 3. The new reporting schedule (fig. 2) shows the proposed due date for this topical report on recovery opportunities.

Task 4 of Phase III is also planned to begin on January 1, 1995, and will last for 18 months (fig. 1). The goal of this task is to conduct technology transfer activities and extrapolate results within and between plays. The central efforts under this task are to prepare a set of workshop notes, develop final reports and publications, and conduct two workshops to transfer results of advanced reservoir characterization to oil operators. Workshops will be held in Corpus Christi and Houston and will provide explicit examples of recompletion and strategic infill drilling opportunities that typify heterogeneous fluvial-deltaic reservoirs within and beyond the Frio play in South Texas.

Extrapolation of the results of this project to other areas will be based on the concept of the geologic play. Much of the information developed about the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) play during this project will be extrapolative to other Frio plays in Texas, including the Frio Deep-Seated Fault Domes play near Houston. Furthermore, the styles of heterogeneity in this fluvial-deltaic play will be transferable to other plays of this origin, for example, the Wilcox Fluvial-Deltaic Sandstone play, deeper Vicksburg reservoirs, and Pennsylvanian deltaic reservoirs of the Strawn Sandstone and Upper Pennsylvanian Shelf Sandstone plays in North-Central Texas. The methodology used in the project will be thoroughly documented so that it can be easily transferred to other fields and reservoirs by operators. This documentation will be made in the topical and final reports and in the workshop notes.

Task 5, the final task of Phase III, will begin late in the coming project year. This task includes the development of a microcomputer-based routine to help direct implementation of well recompletions and strategic infill drilling in fluvial-deltaic reservoirs. Such a microcomputer-based "advisor" will capture the expertise that was developed as part of the project and serve as a means of technology transfer to operators. The "advisor" will proceed from reservoir screening to detailed reservoir analysis and help define for an operator those maps, cross sections, and other displays needed for reservoir redevelopment decisions. The "advisor" would not duplicate current, commercially available software for data analysis, but instead would put those data into a decision analysis framework. Development of such a program, while optimized for fluvial-deltaic reservoirs, could serve as a template for programs applicable to other depositional systems. This task will extend over the final 12 months of the project (fig. 1), ending on August 31, 1996.

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APPENDIX A: List of Publications to Date Associated with DOE Project

1994

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, 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, topical 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.

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.

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. *in press*.

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, *in press*.

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, *in press.*

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