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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
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ABSTRACT

The Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) oil play of South Texas has produced nearly 1 billion barrels (Bbbl) of oil, yet it still contains about 1.6 Bbbl of unrecovered mobile oil and nearly the same amount of residual oil resources. More than half of the reservoirs in this depositionally complex play have been abandoned, and large volumes of oil may remain unproduced unless advanced characterization techniques are applied to define untapped, incompletely drained, and new pool reservoirs as suitable targets for near-term recovery. Interwell-scale geological facies models of Frio fluvial-deltaic reservoirs are being combined with engineering assessments and geophysical evaluations in order to characterize reservoir architecture and flow-unit boundaries and to determine the controls that these characteristics exert on the location and volume of unrecovered mobile and residual oil. These results will help identify specific opportunities to exploit these heterogeneous reservoirs for incremental recovery by recompletion and strategic infill drilling.

Progress during the third project year centered on technology transfer activities. The reserve-growth potential of reservoirs in two fields within the play, Rincon field in Starr County and Tijerina-Canales-Blucher field in Jim Wells County, was documented in a Topical Report published by DOE and in this report. Specific opportunities to exploit untapped and incompletely drained compartments were identified. Results of this effort were also presented at both local and national technical meetings and in two courses hosted by related programs. Preparations have begun for two workshops centered around the activities of this project, as well as the construction of a microcomputer-based Geologic Reservoir Characterization Advisor (GRCA).

The short courses, scheduled for April and June 1996, along with the GRCA, will demonstrate for operators of this mature play the potential that remains in reservoirs threatened by premature abandonment and will document methods for locating and efficiently recovering the tremendous remaining resource. The integrated multidisciplinary characterization methodology demonstrated in this project is applicable to reservoirs throughout the Frio Fluvial-Deltaic Sandstone play, to other fluvial-deltaic plays within the Gulf Coast, and more broadly to any mature fluvial-deltaic play in the United States.

INTRODUCTION

Fluvial-deltaic sandstone reservoirs represent significant opportunities for redevelopment in mature fields throughout the world. At present they account for more than 34 billion barrels (Bbbl) 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. 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. These unproduced zones can be identified by integrated geological and engineering reservoir characterization and can be targeted for near-term incremental recovery by recompletions and infill drilling.

Frio fluvial-deltaic reservoirs are being abandoned at high rates in fields throughout South Texas, but recent resource calculations estimate that more than 1.6 Bbbl of unrecovered mobile oil still resides in reservoirs within a play that has already produced nearly 1 Bbbl of oil (Holtz and McRae, 1995b). Because of the stratigraphic complexity inherent in fluvial-deltaic sandstone reservoirs, significant volumes of mobile oil are commonly isolated in undeveloped reservoir compartments. This large oil resource will remain unproduced unless advanced multidisciplinary reservoir characterization techniques can be applied to identify untapped and incompletely drained compartments that have been overlooked by previous development efforts.

Frio reservoirs in Rincon and Tijerina-Canales-Blucher (T-C-B) fields in the South Texas Gulf Coast were studied to better characterize interwell stratigraphic heterogeneity in fluvial-deltaic depositional systems and to determine controls on locations and volumes of unrecovered oil. Stratigraphic log correlations, reservoir mapping, core analyses, and evaluation of production data were used to characterize variability of reservoirs within the 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. Integrated geologic and engineering reservoir characterization was completed on two selected reservoir zones each within Rincon and T-C-B fields that have experienced different production histories and exhibit different reservoir architectural styles. Development of reservoir flow-unit architecture, described by log facies supplemented with petrophysical core studies and integrated with production data, forms the basis for recognizing the primary controls on hydrocarbon production that, in turn, will directly aid in the determination of reserve growth potential. 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. Total original oil-in-place estimates, however, are in excess of 4 billion stock tank barrels (BSTB), of which 1.5 BSTB is classified as unrecovered mobile oil, and 1.3 BSTB is attributed to residual oil resources (Holtz and McRae, 1995a). 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 objective of this project is to develop a reservoir characterization methodology that leads to determining reserve growth potential. This is being accomplished by developing interwell-scale geological facies models of Frio fluvial-deltaic reservoirs from selected fields in South Texas and combining them with engineering assessments to characterize reservoir architecture and flow-unit boundaries. This characterization has led to an understanding of the location and volume of unrecovered mobile and residual oil. Results of these studies should lead directly to the identification of reserve growth strategies (Table 1).

Table 1. Summary of project objectives.

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

Project Task Breakdown

The project is divided into three major phases (Fig. 1). The first phase included (1) screening fields within the play to select representative reservoirs that have a large remaining oil resource and are in danger of premature abandonment (task 1), and (2) performing initial characterization studies on these selected reservoirs in order to identify the potential for untapped, incompletely drained, and new pool reservoirs (tasks 2–4).

The second phase involved advanced characterization of the selected reservoirs in order to delineate incremental resource opportunities. Subtasks within Phase II included volumetric assessments of untapped and incompletely drained oil, along with an analysis, by reservoir, of specific targets for recompletion and strategic infill drilling. Phase II tasks were completed early in project year 3. The third and final phase of the project, encompassing years 3 and 4, consists

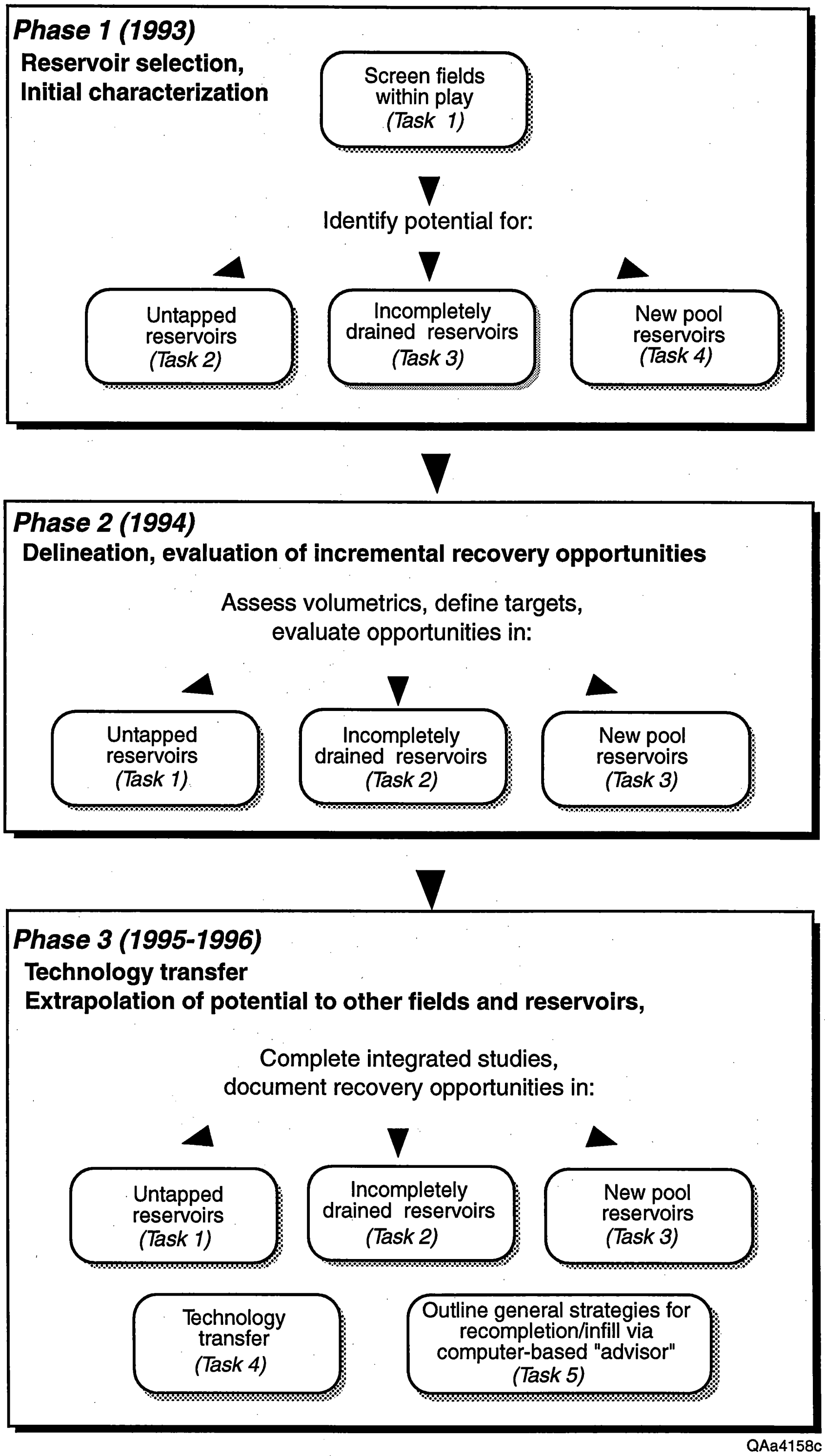


Figure 1. Diagram of work structure for this project illustrating three primary phases and a breakdown of individual tasks associated with each phase of the project. Phase II studies were carried out during the second project year and are the focus of this report.

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 and III that took place during the third year of the contract award, from October 1994 through October 1995.

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) and Holtz and McRae (1995a); 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

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 analysis data by reservoir

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.

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.

Summary of Year 2 Progress

Work performed during the second project year (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 and Whitehill zones in T-C-B field. Reservoir characterization was performed for the remainder of the fiscal year upon this selection of reservoirs.

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

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 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 was published in early 1995. Three separate abstracts were also prepared, submitted, and presented at the annual American Association of Petroleum Geologists meeting held in March 1995. These abstracts highlighted 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 an appendix (p. 177).

OVERVIEW OF PROJECT YEAR 3

Phase III Objectives

The bulk of activity during Project Year 3 focused on Phase III tasks. The goals of Phase III of this project are technology transfer, definition of extrapolation potential, and development of a computer-based geologic reservoir characterization advisor program. The first year of Phase III covers calendar year 1995, when five tasks were initiated.

Tasks 1, 2, and 3 cover documentation of the reserve growth potential of reservoirs for technology transfer. These tasks began on January 1, 1995, and took 7 months to complete. The goal of the tasks was to document results of reservoir characterization and to prepare documentation for reports and technology transfer workshops. A summary of the results of this task was presented as a topical report to the DOE Bartlesville Project Office. Presentations of results were also made at both local and national meetings, including the 1995 GCAGS annual meeting and the 1995 AAPG annual meeting. Two papers were published and presented at the

1995 GCAGS and another three abstracts were published at the 1995 annual AAPG meeting documenting reservoir characterization studies in both Rincon and T-C-B fields.

Technology transfer, task 4 of Phase III, also began on January 1, 1995, and will last for 18 months. 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. Tentative dates have been established for workshops to be held in San Antonio, hosted by the South Texas Geological Society, and in Houston, to be hosted by the Houston Geological Society.

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 extrapolated 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. Documentation of this methodology will be made in the topical and final reports and in the workshop notes.

Development of a geologic reservoir characterization advisor (task 5), the final task of Phase III, has commenced. This task includes the development of a microcomputer-based program to describe and teach users the methodology of reservoir characterization in fluvial-deltaic reservoirs.

Summary of Year 3 Results

Work performed during this reporting period (October 1994–October 1995) consisted of the completion of Phase II tasks associated with delineation of incremental recovery opportunities in selected Frio reservoirs in Rincon and T-C-B fields, as well as Phase III tasks focusing on technology transfer. Specific significant accomplishments are listed in Table 4. Reserve-growth potential for the Frio D and E reservoirs of Rincon field and the Scott and Whitehill reservoirs of

Table 4. Significant accomplishments in Project Year 3: 1994–1995.

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

T-C-B field have been identified (Phase II, tasks 1–3), and specific recompletion/infill drilling opportunities in incompletely drained or untapped compartments and new pools have been documented (Phase III, tasks 1–3). The technologies developed and used in the reservoir characterization process have been transferred to several industry groups through numerous papers and presentations at technical conferences (see list in the appendix), as well as at short courses developed through other Bureau projects (Phase III, task 4). Additionally, a Topical Report documenting reservoir characterization strategies used in Rincon field was accepted and published by the Department of Energy (McRae and others, 1994). Planning and scheduling has begun for two project workshops to be held in San Antonio and Houston during April and May of 1996, and work has begun on a set of course notes to be supplied to attendees (Phase III, task 4). In addition, the general framework for a microcomputer-based geologic reservoir characterization advisor software package has been established, and programming of a test version has begun (Phase III, task 5).

RESERVOIR CHARACTERIZATION METHODOLOGY

by M. H. Holtz

Reserve Growth and the Need for Reservoir Characterization

Reserve growth is a process that begins with the idea that it is possible to add value to a hydrocarbon property. Additional technology and/or changes in socioeconomic conditions can stimulate reserve growth (Fig. 2). Additional technology can improve the efficiency of reservoir management and characterization, thereby improving the economics of production and development and increasing field life. In this step all the tasks necessary to apply the technology are undertaken. When the process of reserve growth is stimulated by changes in socioeconomic conditions, reserve growth can happen immediately by extending the project life of producing properties or by making additional properties feasible. If adding projects is the reserve growth process route, the next task is again reservoir management and characterization so that the additional reservoir development can proceed. The process in general is dynamic, occurring repeatedly during the life of a reservoir. As new opportunities arise from changes in socioeconomic conditions, new technology, or increased knowledge about a reservoir, the process of reserve growth once again can take place, thus becoming a cyclic dynamic process.

Socioeconomic conditions have a pronounced effect on oil reserves. The primary controlling elements include oil price, government regulation, and world economic growth and politics. Oil market price swings affect production rates, affect the timing of well abandonment, and determine if additional technology will be implemented to increase recovery. With the large oil price fluctuations present in today's marketplace, price plays an important role in reserve growth. Government regulation also affects reserve growth potential by impacting such factors as tax structure and operating costs. Recently enacted environmental regulations will also have a major influence on reserve growth by increasing operating cost. Additionally, shifting patterns in world economic growth and politics influence supply and demand and thus the need for oil reserve growth.

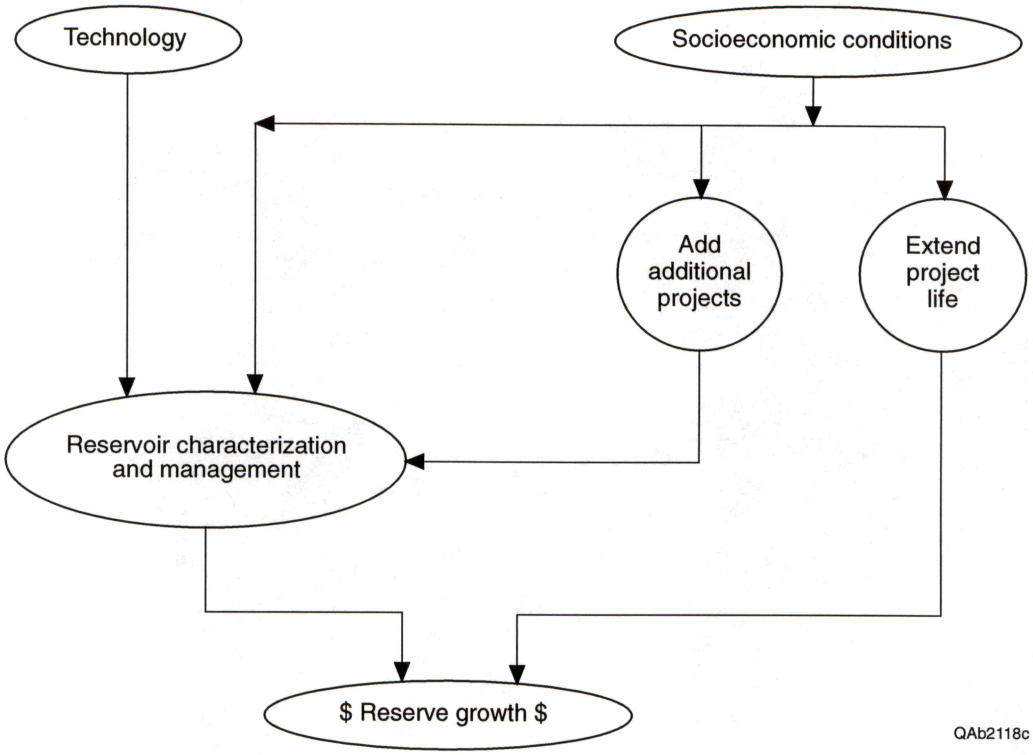


Figure 2. Process of reserve growth stimulated by technology and socioeconomic changes. Reservoir characterization induces reserve additions by targeting resources unrecoverable through existing completions.

Reservoir characterization and management is at the heart of reserve growth. Only when a clear picture of a reservoir is developed can it be determined if a technology should be applied, which properties to apply it to, and what the timing of its application should be.

Reservoir characterization is the building of a geologic and engineering model that describes the reservoir's internal architecture and the distribution of hydrocarbons. The model should incorporate all geologic scales of heterogeneity from gigascopic basin-scale characteristics to microscopic pore-level characteristics. The internal architecture delineated is based on the integration of geologic character with measured engineering parameters. This integration should result in a model that describes all salient fluid-flow paths and barriers. The distribution of hydrocarbons is also a critical element in a reservoir characterization model and follows from the determination of reservoir architecture. Identifying the location within the reservoir of both the initial and remaining hydrocarbon resource allows the model to be applied as a tool for assessing reserve growth potential.

The purpose of reservoir characterization is to develop a fundamental tool that can be applied in determining and optimizing hydrocarbon recovery for reserve growth. A reservoir characterization model applied as a tool allows the assessment of original resource and current reserves and gives fundamental knowledge of how hydrocarbon recovery may be improved. Reservoir characterization is the driving force behind reserve growth.

Methodology

Our ability to model reservoirs at their most fundamental flow unit level is limited because the limited nature of the well-log data sets leaves large areas unsampled between the wellbores. However, important heterogeneities can be recognized in the reservoir with detailed characterization that integrates all available geological, geophysical, and engineering data. The approach to identifying and modeling reservoir character involves four principal steps: (1) determining geologic reservoir architecture, (2) establishing fluid-flow trends in the reservoir, (3) integrating reservoir architecture and fluid-flow trends, and (4) identifying reserve growth potential (Fig. 3). These steps are interrelated, although determining geologic reservoir architecture is the logical first step. These four steps are general, and the level of depth to which they can be implemented is heavily dependent on both the time and data available. The characterization methodology is an iterative process, relying on testing multiple working hypotheses to determine the most probable reservoir model. The key iterative step is integrating reservoir architecture with fluid-flow trends. This key step often is the point at which new hypotheses are developed and old hypotheses are disregarded. The goal of the overall methodology is to determine by what means reserve growth can be accomplished. The following discussion describes each of the four steps of reservoir characterization, culminating in 3-D geocellular reservoir visualization model development and delineation of reserve-growth opportunities.

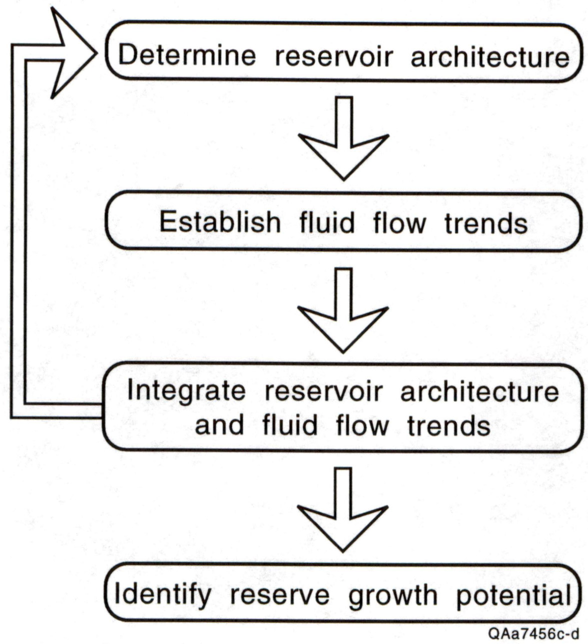


Figure 3. Reservoir characterization as an iterative, four-step process.

Determine Reservoir Architecture

Introduction

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

The internal geometry of sand bodies and the degree of interconnectedness, communication, or compartmentalization between individual reservoir sand bodies is a product of the nonuniformity, or heterogeneity, of a rock reservoir (Alpay, 1972). Reservoir structure can be exceedingly complex, containing heterogeneities from scales of kilometers down to scales of less than 1 millimeter (Lasseter and others, 1986). The scale of heterogeneity that is most critical in controlling fluid-flow pathways and is the key to accessing unrecovered hydrocarbons remaining in the reservoir is the intermediate, interwell, or macroscopic scale of heterogeneity. This level of heterogeneity most closely corresponds to the reservoir flow unit. Macroscale features include variations in depositional and diagenetic facies that serve to compartmentalize a reservoir. Physical bounding elements that define the permeability structure of a reservoir and divide it into separate flow units include both bedding surfaces as well as nonpermeable rock types that act as intrareservoir seals between individual reservoir compartments.

Lateral and vertical reservoir heterogeneity is controlled by the depositional processes responsible for creating the reservoir, and this heterogeneity in turn is responsible for developing the reservoir architecture that provides the fundamental control on hydrocarbon recovery efficiency in a given reservoir unit (Tyler and Finley, 1991). Developing a detailed understanding of the processes, styles, and scales of heterogeneity that characterize a particular reservoir type can become a powerful predictive tool in the identification and delineation of additional unrecovered oil and gas resources.

Workflow Outline

Determining reservoir architecture is the first step in reservoir characterization. This step consists of four basic tasks:

1. Ascertain internal reservoir stratigraphy
2. Compose lithofacies maps to define stratigraphic unit geometries
3. Interpret distribution of depositional environments
4. Combine stratigraphy with structural character.

Reservoir architecture is determined from analysis of the well log, seismic, and core data. Recognizing the internal reservoir stratigraphy of time-equivalent genetic units and their bounding surfaces is the important starting point that allows quantitative facies mapping of the framework reservoir sandstones. Time-equivalent marker beds are recognized on the gamma-ray log and divide the sequence into genetic units. The finer units then form the framework for mapping trends in reservoir geometry as defined by the net-sandstone maps (or percent-sandstone maps if the genetic interval thickness changes markedly) and log-facies maps. Sandstone maps define the geometry of the bed-load fraction of the depositional system and provide a powerful guide to interpreting the processes of sediment dispersal (Galloway and Hobday, 1983). Log-facies maps illustrate the character and distribution of bedding styles and, when combined with sandstone maps, enable construction of a detailed model of reservoir architecture. Systematic areal changes in sandstone geometry or bedding style across the reservoir likely reflect significant facies changes and thus demonstrate heterogeneity that could potentially inhibit fluid flow within the reservoir.

Structure can play an important role in reservoir architecture, so structural mapping of key horizons is an integral part of step one. For example, faulting can juxtapose reservoir sandstones against nonreservoir mudstones, disrupting continuity of the reservoir facies and segmenting the field. Faulting can also juxtapose sandstones of different reservoir quality and introduce partial barriers to fluid flow. Scale of faulting is another important consideration and is dependent on the relative thickness of reservoir and nonreservoir facies and their interbedding relationships. The steepness of structural dip also influences fluid flow in a reservoir and the applicability of certain reserve growth methodologies. Finally, understanding the interrelationship between stratigraphy and paleostructure aids in the delineation of reservoir architecture.

Ascertain Internal Reservoir Stratigraphy

Ascertaining the internal reservoir stratigraphy describes the building blocks of the reservoir architecture. The five main tasks listed below are performed in order to delineate the internal reservoir stratigraphy. They may be worked on concurrently or stepwise depending on the data and manpower available. It is advisable to accomplish the large-scale genetic stratigraphy first in order to have a framework in which to complete the other tasks.

- Describe lithofacies from core
- Integrate lithofacies with petrographic character
- Relate core description to wireline log response
- Determine and correlate finest scale genetic units recognizable on logs
- Delineate missing section and /or stratigraphic pinchouts.

Describe Lithofacies from Core

Whole core is a very valuable set of data that gives the greatest insights into the reservoir's architecture. When core is slabbed, the geologic description should include *lithology, grain size, sedimentary structures, fossils, and bedding surfaces*. These geologic attributes lead to the interpretation of lithofacies and their stacking patterns. Additionally, depositional facies and systems can begin to be hypothesized and potential fundamental bounding surfaces can be identified. Core gives the only firsthand geologic information that can be related to outcrops, modern environments, and geologic process models.

Integrate Lithofacies with Petrographic Character

The goal of petrographic investigation is to *understand mineralogy for wireline log analysis, delineate diagenetic history, and to determine controls on reservoir quality*. Methods of petrographic characterization include thin section description, scanning electron microscopy (SEM), cathodoluminescence, and x-ray diffraction. Sampling strategy must be complete such that one can adequately characterize all rock types, spatial variations both vertical and areal, and relate petrography to any measured petrophysical measurements. Sampling includes obtaining several thin sections from each lithofacies described in core; from vertical successions within lithofacies; over the depth range of the reservoir; and over the horizontal extent that has been cored. Whenever possible, thin section samples should be obtained from core plugs used for petrophysical measurements. In thin section analysis 200 to 300 points should be described to obtain a statistically significant data set. Petrographic data collected include detrital mineralogy, authigenic cements, grain size, sorting, and porosity amount and types.

Relate Core Description to Wireline Log Response

Understanding the geologic controls to wireline response is essential because logs make up the majority of subsurface data. Properly described whole core allows the best correlation between wireline log response and geology. This log-geology correlation can be accomplished following the general steps outlined below:

- Depth shift core to wireline log depth
- Correlate wireline log responses with stratigraphic stacking patterns
- Categorize log response into log/lithofacies.

Core depth often does not match up with wireline depth; therefore, the first step in log-geology correlation is depth matching. Next the relationships between log signature and the described geologic attributed are investigated. For example, an upward-fining grain size described in core may relate to an increasing gamma-ray-log reading. When relationships are established in wells separately, the log-geology correlations between wells should be examined in order to be categorized for depositional system mapping.

Determine and Correlate Finest Scale Genetic Units Recognizable on Logs

The key to proper stratigraphic correlation is the recognition and correlation of large-scale genetic flooding surfaces, working stepwise toward smaller scale bounding surfaces. The general steps in correlation strategy include:

- Recognize and correlate large-scale genetic flooding surfaces
- Interpret basin shape and filling style
- Correlate smaller scale genetic unit surfaces
- Delineate autocyclic bounding surfaces.

High gamma and/or low SP log markers within sandstone systems are used in the recognition and correlation of large-scale genetic flooding surfaces. The best type of marker is dependent on the overall type of basin system. Formation boundaries or the base of regionally extensive shales are good starting points.

With large-scale genetic flooding surfaces correlated, the next step is to interpret basin shape and filling style. Basin shape influences whether a siliciclastic system functions as a point or line sediment source. The geometry of large-scale genetic units aids in interpreting the interaction between sediment supply and relative sea-level fluctuations. A progradation, aggradation, or transgression system will result. These large-scale stacking patterns influence the geometry of the smaller scale genetic bounding surfaces and the corresponding processes.

Correlations of the smaller scale genetic unit surfaces are constrained within the larger scale flooding surfaces. The type and character of these markers are dependent on the larger scale system in which they reside. The geometry of these markers begins to delineate the reservoir architecture on the interwell scale.

Autocyclic bounding surfaces reside within the smallest scale genetic unit. These surfaces define individual depositional facies packages and can be discontinuous on the interwell scale. Mapping on log signatures and lithology isopachs is often needed when interpreting autocyclic bounding surfaces and the depositional facies that they delineate.

Delineate Missing Section and /or Stratigraphic Pinchouts

Anomalies often occur when correlating significant stratigraphic markers. The presence of anomalies should signal the possibility of missing section due to faulting, stratigraphic pinch-outs, or a broken correlation. Determining the most feasible interpretation concepts to pursue requires:

- Observing lateral facies variability for localized thinning trends
- Checking for missing genetic unit/subunit markers
- Looking for faults in seismic data.

These concepts test whether the anomalous heterogeneity observed during correlation is due to stratigraphic changes or structural control. Lateral facies variability can be defined by working concurrently with both lithofacies isopachs and the spatial character of depositional facies/ paleogeographic reconstructions.

Compose Lithofacies Maps to Define Genetic Unit Geometries

Map Types

Lithofacies maps are made in order to define genetic unit and depositional system geometry. When composed these maps highlight salient depocenters and sediment-dispersal pathways, which can be related to paleotopography and/or basement topography, and highlight potential high-quality pay zones. To generate these maps, genetic unit tops are picked and a shale-sandstone cutoff is applied to wire-line logs, leading to lithology thicknesses. The genetic unit and lithology thicknesses are then contoured in relation to hypothesized depositional models. The basic map set that defines genetic unit geometries includes:

- Genetic unit isopachs
- Separate lithology isopachs
- Separate percent-lithology isopachs.

Mapping Strategies

Several concepts are important to apply when developing lithofacies maps. These concepts are based on fundamental sedimentological principles and include:

- Sandstone bodies are generally dip- or strike-oriented to paleotopography
- Sediment-dispersal patterns are normally continuous
- Mapping should reflect depositional facies changes.

Genetic unit isopachs are developed by interpreting unit thicknesses in relation to the hypothesized depositional model and by comparing with log facies signatures. The basin shape and filling style hypothesized during large-scale correlation should be applied and tested when interpreting genetic unit isopachs. For each genetic unit a lithology-indicating log facies map aids in understanding lithology and depositional facies changes within the genetic unit.

Lithofacies maps have a large number of uses. These maps delineate sediment-dispersal pathways displaying the continuity and directionality of each lithology. The shape and directionality are normally related to paleotopography and/or basement structure, and thus these maps are a key to depositional facies interpretation. They also highlight potential high-quality pay zones by delineating the fairways of thickest reservoir-quality rock. As will be mentioned later, they can also function as a geologic trend template in 3-D geocellular modeling to guide the interwell interpolation of petrophysical attributes.

Interpret Distribution of Depositional Environments

The depositional system and facies distribution is determined by interpreting a combination of genetic-unit and lithology isopachs, and log facies maps, within the context of the larger scale basin filling character. The genetic unit and lithofacies geometry relates to the depositional system. For example, basinward-thickening genetic units with dip-elongate sandstone geometries terminating into strike elongate sandstone bodies can signify a fluvial-deltaic depositional system. Within the depositional system, distinct depositional facies can be delineated when the sandstone isopachs are combined with log facies maps. In a fluvial-deltaic system, upward-fining log facies that are coincident with thick dip-elongate sandstone bodies signify a channel facies, whereas an upward-coarsening log facies coincident with thin nondiscrete sandstone bodies indicates a splay. Interpreting the spatial distributions of depositional facies results in the complete interpretation of the internal architecture of each genetic unit.

Combine Stratigraphy with Structural Character

Combining the genetic unit stratigraphy with the structural character results in the final delineation of the reservoir architecture. Constructing structure maps for each mappable genetic unit gives the present 3-D construction of the reservoir. Then by observing both stratigraphic and structural cross sections the interpretation of paleostructure controls on depositional environment distribution is attainable.

Establish Fluid-Flow Trends in the Reservoir

Goals and Procedure

Establishing fluid-flow trends in the reservoir is the second step in reservoir characterization. The *goal* of analyzing fluid-flow trends in the reservoir is *to aid in determining the initial drive mechanism and reservoir architecture, understanding effects of previously applied reservoir management techniques, and to function as a production preprocessor to reservoir simulation.* This step analyzes and incorporates the flow dynamics of the reservoir and is heavily dependent on reservoir engineering concepts of storage capacity and fluid flow in a porous medium. The type of fluid-flow characteristics to be analyzed is dependent on the initial hydrocarbon fluid properties and drive mechanism and on the secondary or tertiary recovery mechanisms applied.

Establishing fluid-flow trends in the reservoir is accomplished through five main tasks:

1. Ascertain the initial hydrocarbon and water fluid properties.
2. Generate a production time series analysis of fluid flow (graphs and maps of oil, gas, watercut and pressure-depletion).
3. Analyze initial and changes in water and hydrocarbon chemistry.
4. Assess well test data.
5. Determine flow directions of injected fluids.

Tools

The tools used in establishing fluid-flow trends include laboratory analysis of hydrocarbons, computer graphing, mapping, and well test analysis (Fig. 4). The key to establishing fluid-flow trends with these five main tasks is to do it in the context of the established reservoir architecture, petrophysical character, fluid properties, and reservoir management. Fluid-flow trends can be better analyzed when the hydrocarbon volumes stored and fluid-flow capacity equations are divided into these characteristics. The hydrocarbon volumes stored equation is a function of reservoir architecture, petrophysical characteristics, and fluid properties (Fig. 5). The areal extent of the reservoir and the net pay thickness define the net reservoir volume and are controlled by the reservoir architecture, having a significant effect on the volume of produced hydrocarbons. The amount of this bulk volume that contains hydrocarbons is directly controlled by the petrophysical attributes, leading to the possibility that a thick interval that produces small volumes may contain low porosity and/or high initial water saturation. The fluid-flow capacity equation is a function of reservoir architecture, petrophysical characteristics, fluid properties, and reservoir management (Fig. 6). Flow rate is directly proportional to the permeability-thickness (kh), which is a combination of reservoir architecture and petrophysical character. Relatively high well flow rates must signify relatively high kh values. Flow rate also increases with increasing pressure drop from the reservoir. With larger hydrocarbon storage capacity, pressure in the reservoir will decrease relatively more slowly, sustaining a higher pressure differential and therefore slowing the decline of hydrocarbon production rate. These general interrelationships, when kept in mind during the analysis of fluid-flow trends, help to integrate the reservoir architecture with the production character.

Ascertain the Initial Fluid Properties

Introduction

The initial fluid properties give valuable insight into how a reservoir will produce and can help explain production anomalies. Basic hydrocarbon fluid properties needed in reservoir

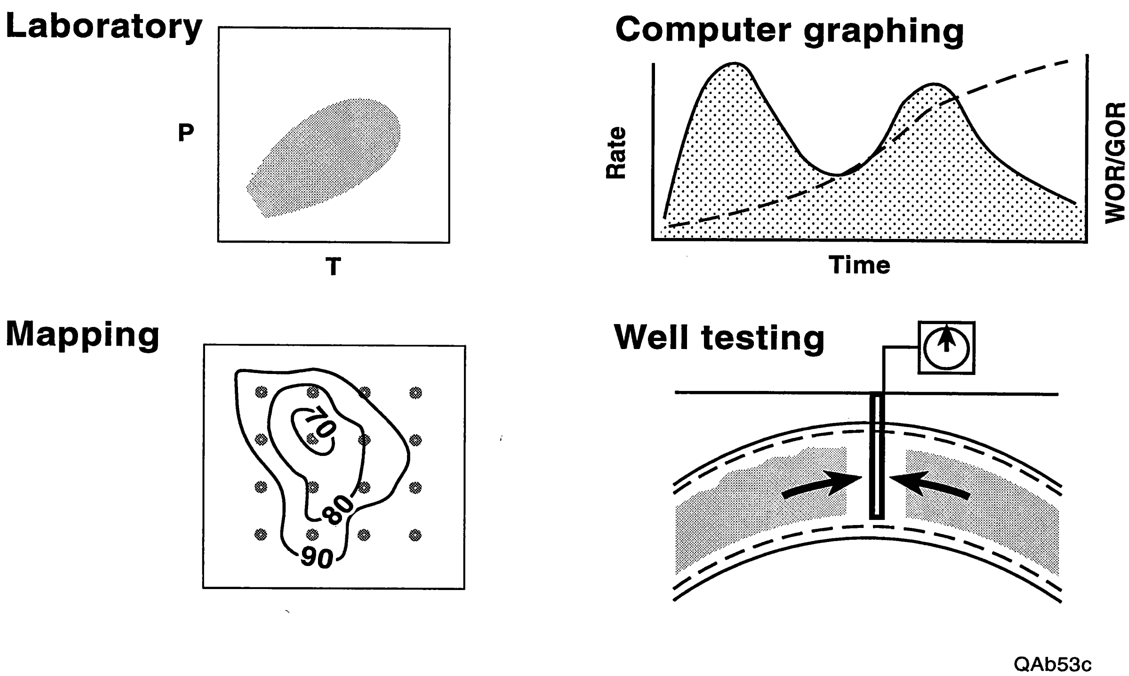


Figure 4. Tools used in establishing fluid-flow trends, including laboratory analysis of hydrocarbons, computer graphing, mapping, and well test analysis.

STORAGE CAPACITY

- Original oil in place $= \dfrac{7758 * A * h * \text{ø} * (1-S_{wi})}{B_{oi}}$
- Reservoir architecture } A = reservoir area (acres); h = reservoir height/net pay (ft)
- Petrophysical characteristics } ø = reservoir porosity; S_{wi} = reservoir water saturation
- Fluid properties B_{oi} = oil formation volume factor

QAb101(a)c

Figure 5. Hydrocarbon storage equation as a function of reservoir architecture, petrophysical characteristics, and fluid properties.

FLOW CAPACITY

$$q \text{ (flow rate)} = \frac{kh\Delta P}{141.2\mu B_o \, \mathrm{Ln}\left(\frac{r_e}{r_w} + S\right)}$$

• Reservoir architecture	h = net pay thickness r_e = drainage radius
• Petrophysics	k = permeability
• Fluid properties	μ = viscosity B_o = formation volume
• Reservoir management	ΔP = pressure drop s = wellbore skin r_w = wellbore radius

QAb101(b)c

Figure 6. Fluid-flow capacity equation as a function of reservoir architecture, petrophysical characteristics, fluid properties, and reservoir management.

characterization include oil and gas gravity, oil and gas viscosity, formation volume factor, gas to oil ratio, and initial water to oil/gas ratio. Salient water properties include resistivity, salinity, and cation and anion concentrations. Below is a description of how these properties can give insight into the character of a reservoir.

Hydrocarbon Properties

The primary source for determining initial hydrocarbon fluid properties is pressure-volume-temperature (PVT) analysis and a secondary source is initial well production. Hydrocarbons are subdivided into heavy and light oil, dry and wet gas, and retrograde condensate gas on the basis of distinctive PVT properties. Knowledge of the initial hydrocarbon fluid properties from PVT analysis and/or initial well production directs which production fluid characteristics should be monitored and when changes in those monitored characteristics are giving insight into the reservoir.

Pressure-Volume-Temperature (PVT) Properties

A generalized multicomponent phase diagram (Fig. 7) can be used to illustrate the fluid property differences between low-shrinkage and high-shrinkage oil, dry and wet gas, and retrograde condensate gas. The phase diagram illustrates how temperature and pressure control whether a hydrocarbon exists as a liquid, gas, or both within a reservoir. At pressures above the bubble-point line, a hydrocarbon exists as a liquid, whereas at pressures below the dew-point line a hydrocarbon only exists as a gas. These two lines meet at the critical point, a temperature and pressure at which a hydrocarbon demonstrates the properties of both a liquid and a gas. Both liquid and gas coexist together in the region of pressures and temperatures between the bubble point and dew-point lines. In an oil reservoir, if the original pressure is above the bubble-point line, the liquid is undersaturated with respect to gas, at the bubble-point the oil is saturated, and below the bubble-point the oil is associated with gas normally as a gas cap.

At high temperatures above a line defined as the cricondentherm a hydrocarbon will remain a gas, regardless of the change in pressure. The cricondentherm line is important because as a reservoir is produced it remains at a constant temperature as pressure is reduced. Therefore, if a reservoir lies at a temperature below the cricondentherm, the possibility exists for the presence of both liquid and gas within the reservoir as pressure is reduced, whereas if the reservoir lies above the cricondentherm the hydrocarbon will remain a gas, regardless of the pressure drop (Fig. 7). As will be discussed later, inducing multiple phases within the reservoir from pressure depletion has a profound negative effect on the ultimate recovery efficiency of the reservoir.

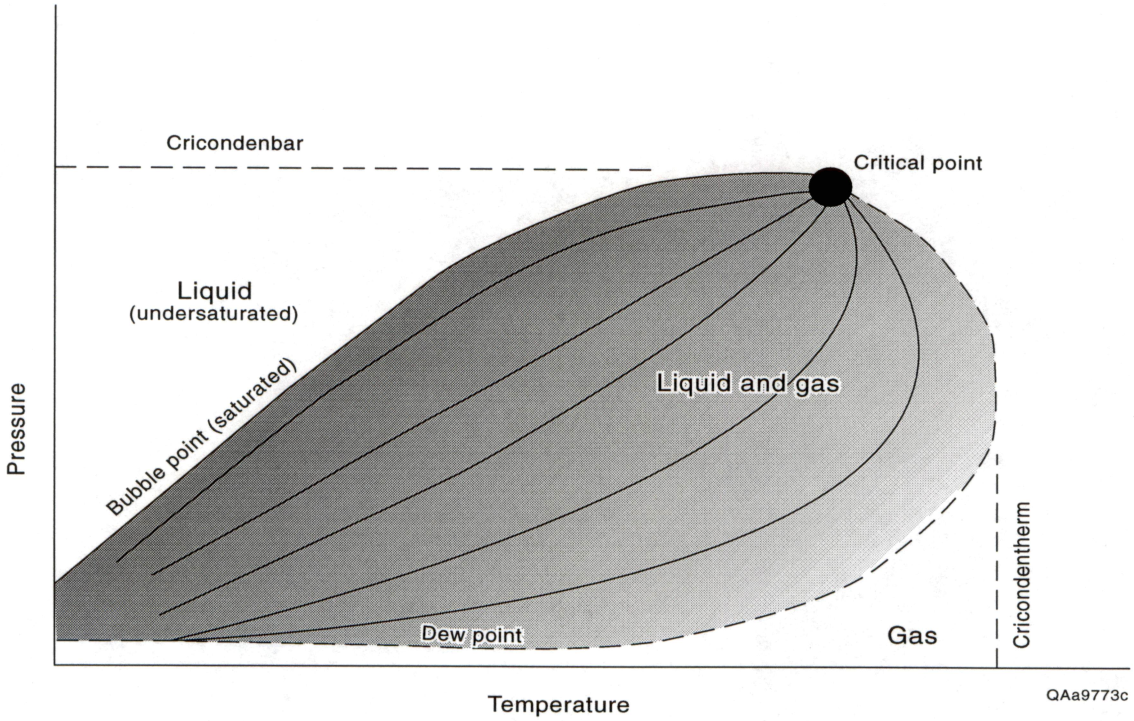


Figure 7. Generalized PVT graph displaying nomenclature.

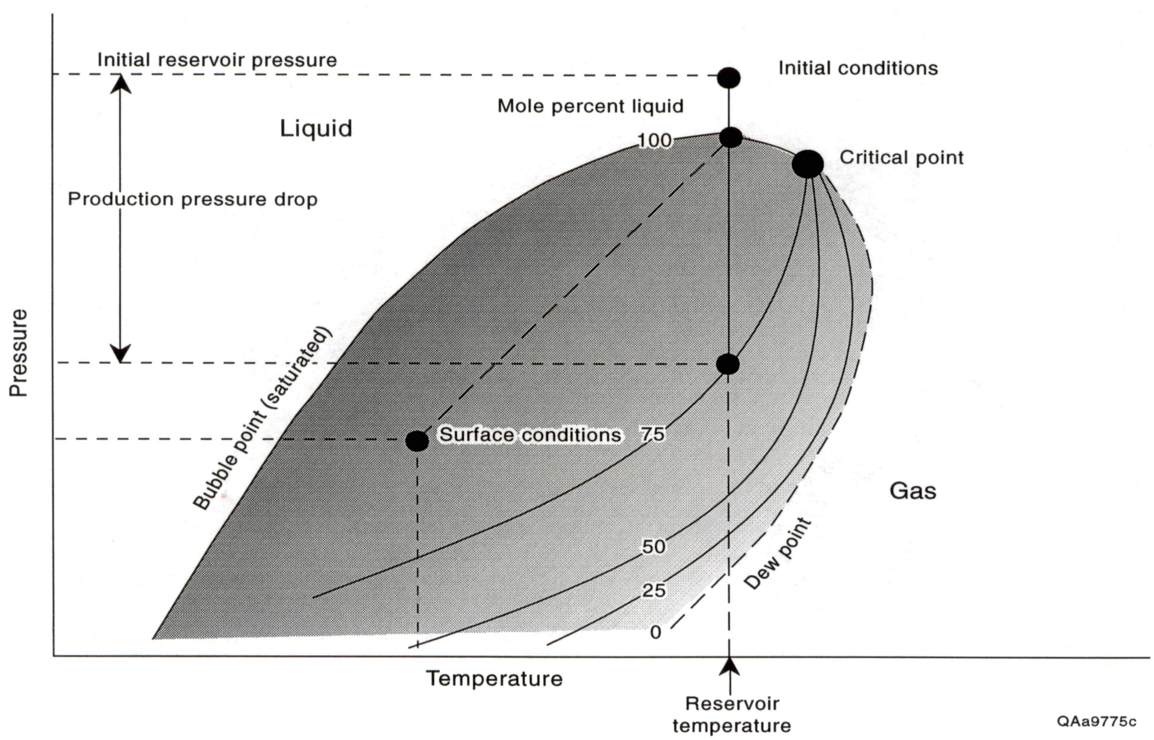


Figure 8. The PVT character of low-shrinkage oil, which causes a lower relative bubble point pressure and results in the phase diagram percent liquid lines being shifted toward lower pressures.

Important PVT properties for oil include oil gravity, solution gas-oil ratio, bubble point pressure, gas gravity, formation volume factor, and oil viscosity. All of these properties are interrelated. When characterizing a reservoir it is important to understand both the initial property conditions and how these properties change with pressure. This understanding is gained from observing the nature of the oil's phase diagram.

Low-shrinkage oils are typified by API gravities of less than 30° and produce at initial GORs of less than 500 scf/STB (McCain, 1973). The lower oil gravity and GOR is a direct result of the liquids being composed of primarily heavier hydrocarbons. This causes a lower relative bubble point, and the phase diagram's percent liquid lines are shifted toward lower pressures (Fig. 8). If the reservoir is initially above the bubble point, the oil is undersaturated and an initial decrease in pressure does not result in gas coming out of solution in the reservoirs. With additional production pressure drop, a reservoir can reach the bubble point and the oil becomes saturated. Pressures below the bubble point line result in the presence of gas. However, because of the shifted percent liquid lines a substantial portion of the hydrocarbon remains a liquid; therefore, less shrinkage occurs, resulting in a formation volume factor close to unity. The majority of the hydrocarbon remains a liquid when taken to surface conditions. The heavier hydrocarbons also cause relatively greater oil viscosity. Low-shrinkage oil normally resides in reservoirs at lower pressures and temperatures and at shallower depths than light oil.

High-shrinkage oils are characterized by API gravity greater than 30° and initial GOR greater than 500 scf/STB. A greater portion of the oil consists of lighter hydrocarbons, resulting in a higher bubble-point pressure and a shifting in the phase diagram of percent liquid lines toward higher pressures (Fig. 9). As reservoir pressure is initially reduced, the hydrocarbon functions similar to the heavy oil. However, when the reservoir pressure drops below the bubble-point a much greater portion of the oil becomes gas, resulting in elevated producing GOR, greater shrinkage of the oil, and thus a formation volume factor much larger than unity. The high-shrinkage oil is less viscous; however, it becomes more viscous as more of the light hydrocarbons are produced in the form of gas. High-shrinkage oil normally resides in reservoirs at higher pressures and temperatures and at deeper depths than heavy oil.

Retrograde condensate gas has phase properties that allow the possibility of both liquid and gas to reside within the reservoir. A retrograde condensate gas reservoir is initially at a temperature greater than the critical point but less than the cricondentherm. The initial pressure is sufficiently high that the hydrocarbon is in a gas phase. As production proceeds and pressure is reduced below the dew point, liquid comes out of solution; therefore, both gas and liquid reside in the reservoir (Fig. 10). The preferential movement of gas in the resultant two-phase flow reduces the ability to produce the liquid portion. Low recovery efficiency of the total original hydrocarbon volume results.

Classification of a gas as wet or dry also depends on the PVT properties and separator conditions. A wet or dry gas is initially at reservoir conditions above the critical point and at a temperature above the cricondentherm. As production reduces pressure within the reservoir the gas stays single phase because it is above the cricondentherm. When the produced gas reaches the separator conditions a wet gas passes the dew point and a portion of the hydrocarbon becomes liquid. However, a dry gas does not cross the dew point at separator conditions but remains in the gas phase (Fig. 11). Because two phases do not coexist within the reservoir pressure depletion does not adversely affect recovery efficiency.

Analyzing Initial Well Potential Tests

Analyzing initial well potential tests provides a picture of reservoir fluid-producing potential and hydrocarbon fluid properties during the early stages of reservoir development. Mapping initial well potential highlights reservoir sweet spots and can also point out early any areal differences that may be a result of lateral heterogeneities. Statistics of such fluid-flow characteristics as initial gas-oil ratio (GOR), water-oil ratio (WOR), water-gas ratio (WGR), and gas-condensate ratio (GCR) give a benchmark by which to compare changes in fluid flow over time. They can also aid in understanding the initial hydrocarbon fluid properties in the absence of PVT data.

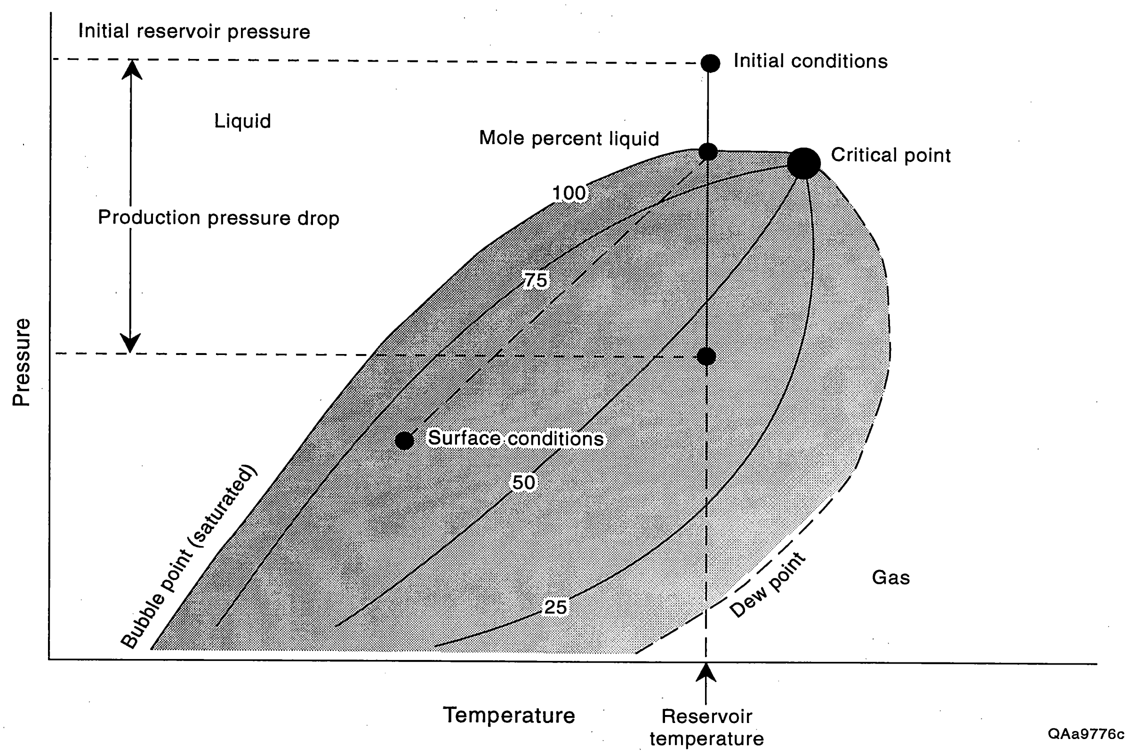


Figure 9. A greater portion of high-shrinkage oil consists of lighter hydrocarbons, resulting in a higher bubble-point pressure and a shifting in the phase diagram of percent liquid lines toward higher pressures.

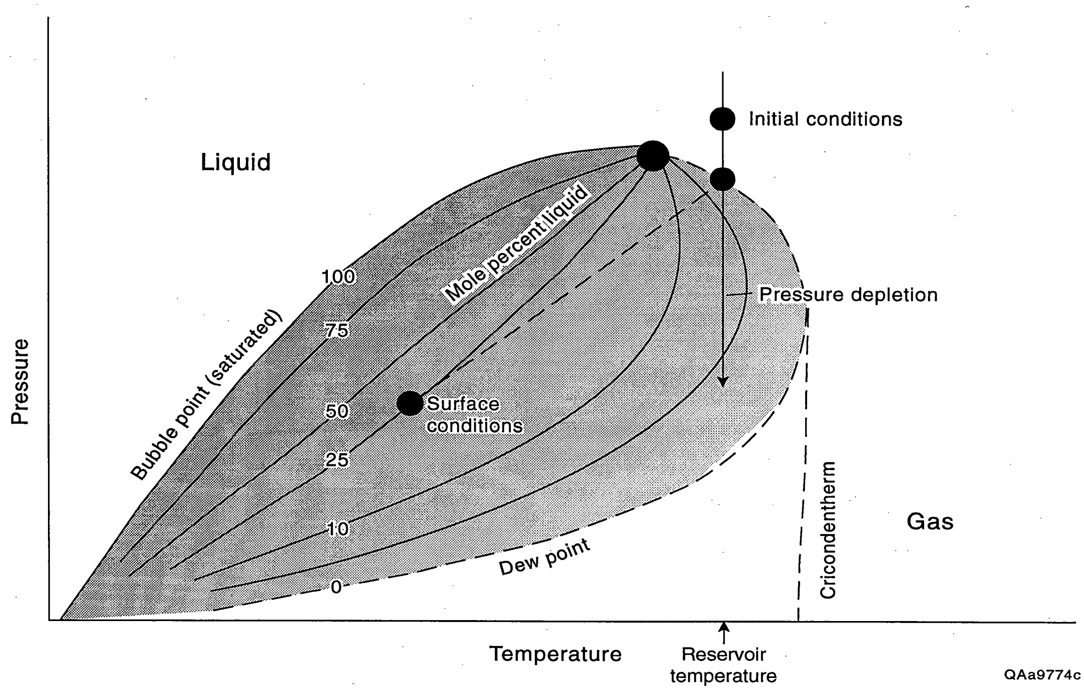


Figure 10. As production proceeds and pressure is reduced below the dew point, liquid comes out of solution. Therefore, both gas and liquid reside in the reservoir.

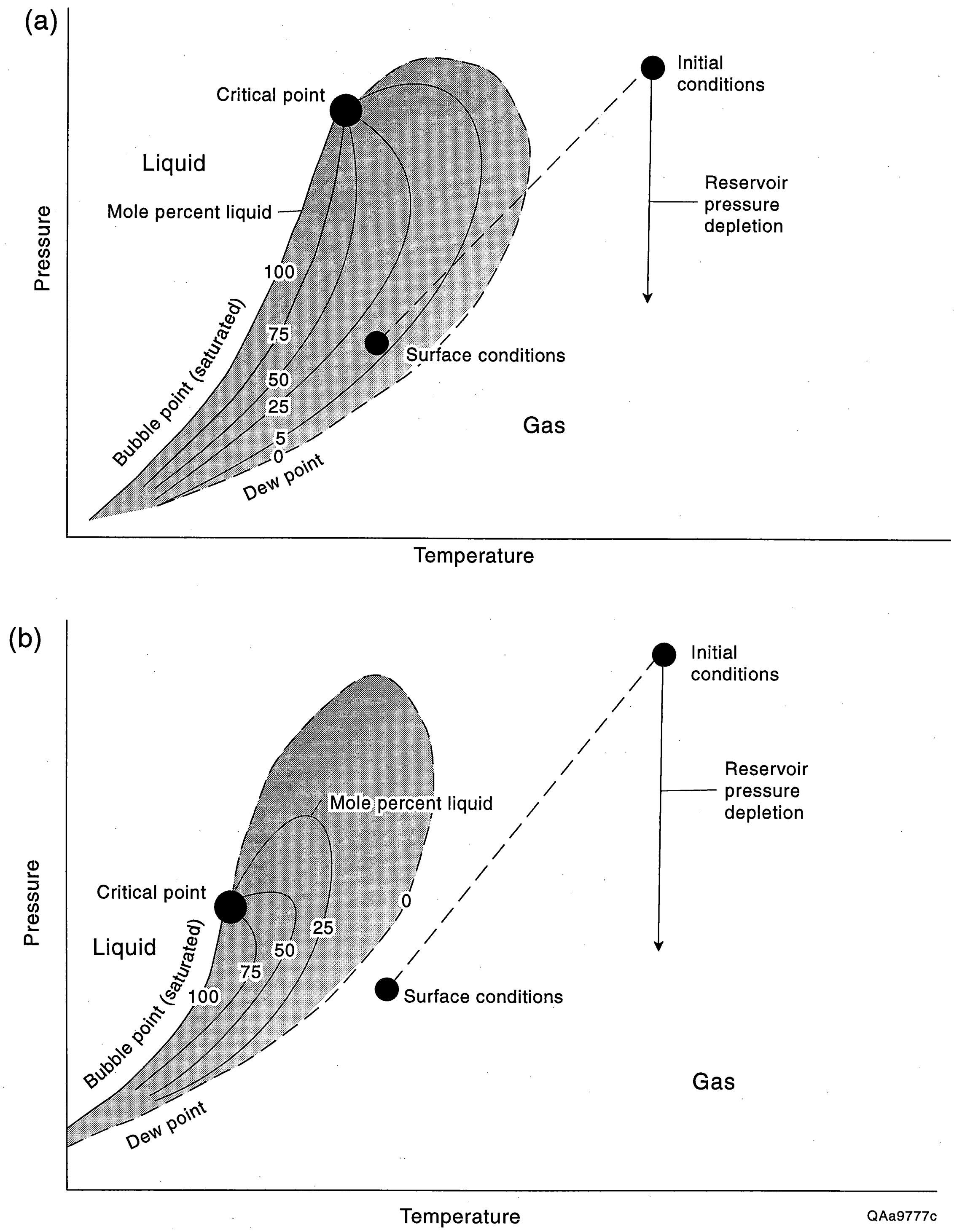


Figure 11. When the produced gas reaches separator conditions, a wet gas passes the dew point and a portion of the hydrocarbon becomes liquid. However, a dry gas does not cross the dew point at separator conditions but remains in the gas phase.

Water Properties

An understanding of initial water properties is critical in the calculation of water saturation and can aid in the determination of internal reservoir flow barriers. Laboratory analysis is the main source for obtaining water properties, but wireline logs can also be employed. Properties of interest include water resistivity, salinity, and cation and anion concentration.

Generate a Production Time Series Analysis

Introduction

There are three tasks in generating a production time series analysis:

- Compile completion and plugback information on maps and logs
- Graph production and annotate with reservoir management history
- Map and analyze time series history of fluid production.

The production time series analysis has three reservoir characterization objectives. These objectives are to determine the initial reservoir drive mechanism, to understand the effects of previous reservoir management techniques, and, most importantly, to understand how the reservoir architecture has influenced fluid flow. The combined influence of these three factors is what has created the reservoir's production history. Knowledge of their relative effects is critical in reservoir characterization and in determining reserve-growth potential.

Production Time Series Graphing and Mapping

A time series analysis of fluid flow consists of graphing and mapping of oil, gas, water cut, and pressure-depletion variation over the producing life of the reservoir. Graphing of all produced fluids and pressure is done on both a reservoir and a well level. Reservoir level graphs, in addition to production of all fluids, should include the number of wells on line and should be annotated with the timing of any reservoir management changes such as the implementation of secondary or tertiary recovery. Graphs are developed such that they capture the shortest interval for which data are taken and are annotated with any workovers that may affect the well performance such as pumps, frac jobs, recompletions, and so on. Fluid-flow trends within the reservoir are also established from a set of production performance maps that illustrate initial potential, cumulative and current production, GOR, water cut, and pressure depletion on a per-well basis. Analysis of these maps captures the historic changes in fluid production throughout the reservoir and highlights important trends in fluid flow. Areas of best production (sweet spots) as well as areas showing impedance to fluid flow are readily identifiable.

Another key is whether the oil in the reservoir is undersaturated or saturated with solution gas. An undersaturated oil reservoir can produce substantial volumes of oil with a significant pressure drop before gas will come out of solution in the reservoir. This will be seen in a steady producing GOR at a value near the initial solution gas to oil ratio. In contrast, a saturated oil begins to produce at elevated GORs soon after production with only a minor pressure drop.

A time series set of water cut and pressure maps also illustrates fluid-flow trends. These maps record the pattern of water migration as reservoir pressures decrease and can highlight preferential pathways of fluid migration, most likely indicating fairways of high transmissivity and thus reservoir communication. Anomalies in these maps can indicate barriers to fluid flow and thus reservoir compartmentalization.

Comparison of the initial hydrocarbon fluid characteristics and the time series analysis is the primary aid in determining the initial drive mechanism. Monitoring GOR can indicate whether gas cap expansion or solution gas drive, or both, are the functioning drive mechanism. Rapidly increasing GOR near the crest of the structure can indicate gas cap expansion in a reservoir containing initial oil characteristics above the bubble point pressure. A fairly uniform increase in GOR around the field can indicate a solution gas drive mechanism. A time series of WOR that displays increases over time up structure can indicate a water drive mechanism.

Water Production Analysis

Water production is one of the most critical fluid flow trends to understand in identifying reserve growth potential. The production of water can indicate encroachment of an aquifer, rendering portions of a reservoir void of reserve growth potential. However, water can often finger or channel into the productive interval, leaving substantial reserve growth opportunities behind. The risk of additional reservoir development can be substantially reduced when detailed water production analysis is incorporated into a reservoir characterization model.

Characteristics of Aquifer Encroachment

Aquifer encroachment decreases ultimate recovery in gas reservoirs. Encroaching water traps residual gas behind the invading water front and maintains reservoir pressure. These effects reduce the volume of gas that will be produced, as compared with conventional pressure depletion. Also, as water volume flowing into the well bore increases, loading can eventually occur, and this will effectively kill the free flow of gas, resulting in down time, sporadic well production, costly well maintenance, and ultimately, abandonment of the well. Additionally, high volumes of produced water can increase disposal costs, rendering a well uneconomic. Careful planning, design, reservoir characterization, and well handling are needed to maximize gas recovery when aquifer encroachment occurs.

In contrast to gas reservoirs, oil reservoirs can benefit from aquifer encroachment. Water encroachment from a connected aquifer can act as a water drive, maintaining pressure and displacing oil. The maintenance of pressure sustains flow rates, and the displacement of oil by water increases sweep efficiency.

Aquifer and hydrocarbon reservoir characteristics and production history govern water encroachment, and understanding these factors is critical to optimizing oil and gas recovery. The main aquifer attributes that influence a hydrocarbon reservoir are aquifer size, pressure, and geologic character. Size and pressure characteristics affect the pressure support transmitted to the hydrocarbon reservoir. The larger the aquifer size relative to the hydrocarbon reservoir (dimensionless radii), the greater and longer the pressure support and the lower the recovery efficiency. A greater pressure differential between the aquifer and a depleting gas reservoir can reduce ultimate recovery. Recovery efficiencies for gas reservoirs and aquifers at lower initial pressures will be less affected by aquifer encroachment, whereas higher pressure systems may result in more rapid water encroachment (Agarwal and others, 1965). Permeable and homogeneous aquifer/gas reservoir systems undergo more rapid water encroachment at higher reservoir pressures and thus have lower gas recovery efficiency. Also, higher residual gas saturation resulting from pore geometry and higher relative permeability to water will lead to lower recovery efficiency. High residual oil saturation occurs when pressure depletion is not uniform in the oil leg and when the oil has high viscosity relative to the encroaching water. Overall, characteristics that promote water influx and decrease oil or gas reservoir incremental pressure drop cause lower recovery efficiency.

Production history also influences aquifer encroachment. An increased gas production rate can result in an increased recovery of gas (Agarwal and others, 1965; Matthes and others, 1973; Lutes and others, 1977). An increased production rate often leads to greater pressure depletion before wells water out and thus results in greater gas recovery. The performance parameters proposed by Hower and Jones (1991) illustrate the interrelationship between gas flow rate and reservoir characteristics. High production rates, however, must be designed so that no coning or fingering occurs. Relative permeability and residual gas saturation are important considerations in the effectiveness of higher production rates. Permeability, relative permeability, and residual gas saturation characteristics affect the broadness of the pressure gradient between gas reservoir and aquifer. A broad pressure gradient will increase the water-invaded zone and result in a larger volume of trapped gas. Oil recovery is increased when reservoir pressure depletion is uniform. This reduces water fingering and, thus, bypassed oil as the aquifer water front encroaches.

Interpreting Field Data

Determining the movement of water into an oil or gas reservoir characterizes the aquifer/ hydrocarbon reservoir interaction and aids in reservoir development. Modeling the direction of encroachment is best accomplished by analyzing water/gas ratios (WGR), reservoir pressure, oil-water cut (percent water), downhole production logging tool response (spinner tests), and produced-water characteristics in a time series of maps. This analysis is dependent on monitoring data at short time intervals so that significant trends can be observed. Map time-series observation facilitates determination of fluid movement in three dimensions, is key to integration of geology and engineering, and aids in reservoir simulation. Increases in WGR can occur from four different scenarios: (1) water coning or fingering, (2) reservoir communication with a small passive aquifer, (3) reservoir communication with a strong aquifer, and (4) communication with a water zone behind casing.

Increasing water-oil or water-gas ratio (WOR/WGR) is the first frontline observation signifying a water production problem and possible aquifer encroachment. At the onset of increasing WOR/WGR, the possibility that water coning or fingering is occurring in a single well must be suspected. This is brought about by a well bore pressure drawdown that is high enough to cause a local change in the OWC such that it comes in contact with the well bore. Reservoirs that have good permeability and/or high permeability heterogeneity are most susceptible to coning and fingering. Diagnostic features of coning or fingering include rapidly increasing WOR/WGR or WOR/WGR increasing in only one well while others at structurally equivalent positions show no WOR/WGR increase (water cross-cutting structure). This cross-cutting of structure can occur in multiple wells. Coning or fingering may occur when WOR/WGR increases rapidly immediately after drawdown on a well has been increased. In some cases, production logging tools can identify whether water is coming from the lowest perforations. A time series of WOR/WGR maps will show a rapid increase in WOR/WGR in localized spots (like target bull's-eyes). Over time, WOR/WGR will increase in those wells that have coning or fingering problems.

WOR/WGR can also increase when a passive or small aquifer is connected to a reservoir (no water drive or only a weak one). In this scenario, a steady WOR/WGR increase will occur with a large drop in overall reservoir pressure over an extended period. Aquifer encroachment will gradually follow upstructure, with the oil-water contact rising on a reservoir scale. Local variation in permeability may cause more rapid localized WOR/WGR changes; however, it is unlikely that water encroachment will cross-cut structure significantly.

A strong water drive aquifer can cause the WOR/WGR to increase early in the production life of a reservoir. Encroachment of water will follow upstructure, increasing the WOR/WGR over time, corresponding to overall reservoir pressure drop, and resulting in lower cumulative hydrocarbon production.

The final scenario that can increase WOR/WGR is communication with a water zone behind casing. Water problems occur when poor casing cementation permits water to move between the casing and formation. If a water-behind-casing problem results from a poor cement job, the initial WOR/WGR may be high and the well may appear to have been completed in the hydrocarbon/water transition zone. When the cement job deteriorates over time, the WOR/WGR may increase slowly. Water-behind-casing problems can be diagnosed when increasing WOR/WGR does not correspond to reservoir cumulative production or pressure changes and when the problem does not occur in other wells.

Monitoring and analyzing reservoir pressure can determine whether water problems are related to one of the four scenarios described above and can indicate direction of water influx. Aquifer encroachment causes the rate of pressure depletion to decrease over time with increasing cumulative production. Neither coning and/or fingering nor increased WOR/WGR from water behind casing will provide pressure support. A passive aquifer will provide little pressure support.

By mapping and interpreting material balance plots, the area for which pressure support is occurring can be determined. Figure 12 illustrates the effect different reservoir characteristics have on material balance plots. Strong evidence for pressure support is provided when the

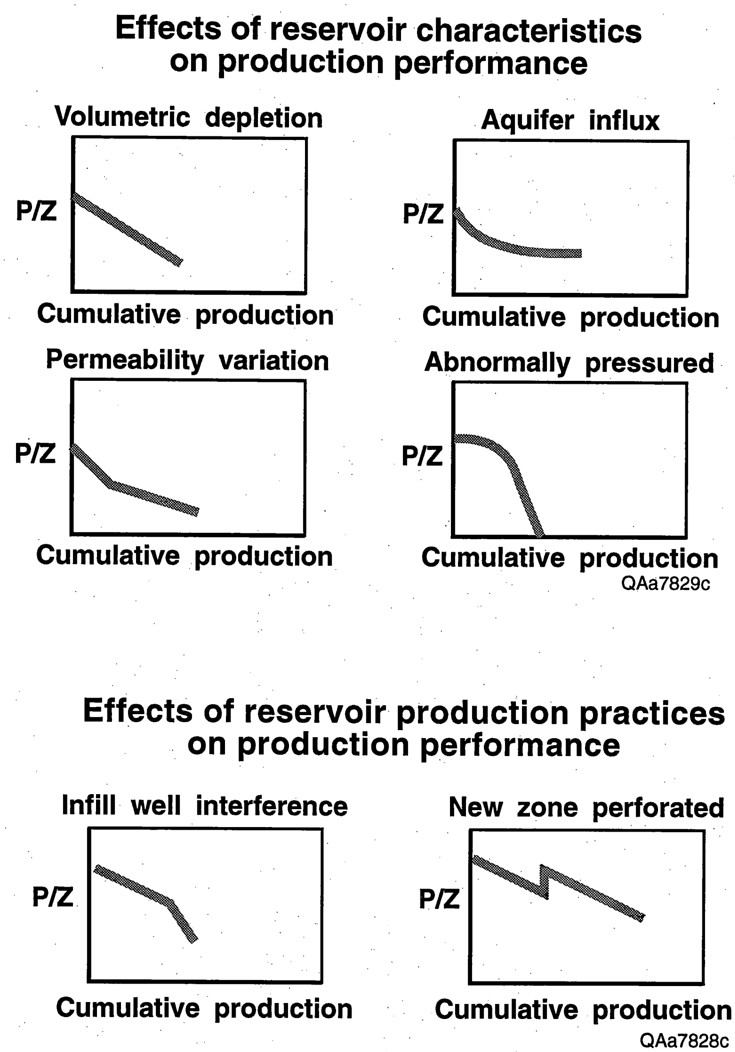


Figure 12. The effect that different reservoir characteristics and production performance practices have on material balance plots.

pressure support corresponds to rapid increases in WOR/WGR upstructure. The direction of increasing WOR/WGR and pressure support illustrates the direction of water encroachment.

Production logging tools (spinners) can also assist in determining the characteristics of water production. These tools demonstrate what water volume, different perforations, and/or sandstone zones contribute to total water production. When water is coming almost exclusively from upper perforations, communication with a water zone behind the casing should be suspected; when only the lowest perforations are contributing to water production, however, coning or fingering should be suspected. A specific reservoir sandstone connected to an aquifer may be isolated in the case of multiple sandstone zones. Information gained from production logging tools can guide the use of dual completions, permeability profile modification, and/or selective perforation plugging.

Monitoring produced-water chemistry can also indicate the origin of a water. Changing water chemistry should be analyzed over time and between wells. Freshening of produced water may indicate communication with a water zone behind the casing above the reservoir (water dumping), whereas increasing salinity may indicate production from an aquifer that is more saline than the connate water. Proper interpretation can be accomplished only when the specific reservoir water chemistry (as well as that of the overlying and underlying aquifers) is known.

Assess Well Test Data

Introduction

Well tests are an important source of information on reservoir architecture, petrophysics, and reservoir management. Well testing is divided into two types, pressure transient testing and production logging. Pressure transient testing involves producing pressure variations in a well bore over time and subsequently measuring pressure differences. The character of a volume of reservoir in pressure communication can then be interpreted by analyzing these pressure differences. Production logging involves downhole measurements that record vertical variations in reservoir characteristics.

Pressure Transient Testing

Pressure transient testing provides information on reservoir architecture, petrophysics, and reservoir management. Four basic types of tests include

- Buildup and drawdown tests
- Interference and pressure pulse tests

- Injectivity tests
- Drill-stem tests.

Analyses of pressure transient tests fundamentally stem from the rate equation illustrated in Figure 6. By measuring flow rate and pressure, the reservoir architecture characteristics of net pay, drainage radii, and flow-unit compartment boundaries can be analyzed. The total permeability of the flow unit tested is also determined along with well-bore skin effects. Drill-stem tests (DSTs) allow the sampling of downhole fluids, the measuring of static downhole pressure, and the testing of well productivity. Overall pressure transient tests describe how a well will perform as a result of both the reservoir character and any wellbore damage that may have occurred.

Drill-stem tests can be very useful in both the initial development of a reservoir and subsequent reevaluations. Initially the DST can be used to gather the first reservoir fluid samples that allow the analysis of initial fluid properties. The DST gives a measure of the static bottomhole pressure that is used in production design and is the benchmark when analyzing reservoir pressure depletion. Potential well productivity is a result of the hydrocarbon flow rate test as well as kh and skin determination. The DST is the front-line indicator of the commerciality of a new reservoir. DSTs in infill development wells result in testing how fluid characteristics have changed and how pressure has depleted since initial development. This valuable information can lead to the delineation of aquifer encroachment and the recognition of underproduced zones within a reservoir.

Production Logging

Production logging tests the vertical variations of reservoir character and may also indicate behind-pipe problems. The four most common tests include

- Spinner tests
- Tracer tests

- Temperature survey tests
- Repeat Formation Tester (RFT)*.

Spinner tests measure the relative flow rates into the wellbore and are useful in determining thief zones in the case of waterflooding. Zones that indicate good reservoir quality from open-hole wireline logs but show poor flow character from spinner tests may have high near-wellbore formation damage or poor perforations. Tracer tests and temperature surveys indicate how fluid is flowing within the reservoir or just behind pipe. The Repeat Formation Tester (RFT)* allows open-hole testing of the pressure at specific points, resulting in the ability to test and compare pressure depletion between flow units.

Integrate Reservoir Architecture and Fluid-Flow Trends

Workflow outline

Integration of reservoir architecture with established fluid-flow trends is the critical third step in reservoir characterization. This step forms the basis for testing and interpreting the working hypothesis of reservoir architecture, and the outcome becomes the working model on which reserve growth strategies are based. The workflow for this step is shown in Figure 13. The initial task is to identify correspondence between stratigraphic-unit geometries, structural setting, and fluid-flow trends. The goal of this initial step is to determine what portion of the stratigraphic and structural heterogeneity is influencing fluid flow within the reservoir. The second task has two concurrent subtasks of designing petrophysical models and establishing reservoir flow units. It is important that this second task come after the first since petrophysics and flow units should be modeled at the scale where geologic architecture controls fluid flow in the reservoir. The third task is to determine the distribution of petrophysical properties within the reservoir. This task has traditionally been accomplished by summing or averaging calculated properties at the wellbore and then mapping them in two dimensions. However, with the advent of greater computing

*Mark of Schlumberger

power, the distribution of petrophysical properties is being modeled in three dimensions. The advantage of this is that little or no averaging of the wellbore data is needed. Additionally not only is the intrawell property distribution being accomplished deterministically but also stochastic methods are being employed. The final task is to calculate the original hydrocarbons in place. This is accomplished volumetrically from the petrophysical distribution and allows the characterizer to begin investigating reserve growth potential.

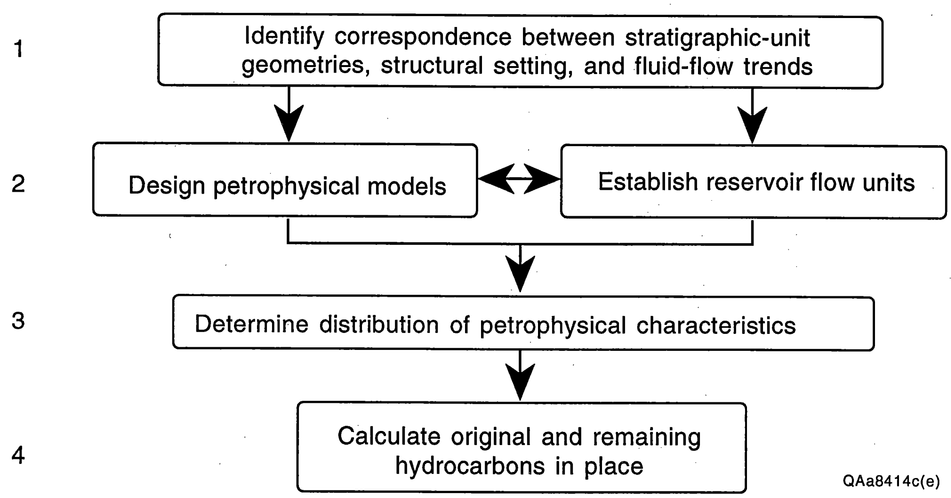


Figure 13. Integrating reservoir architecture and fluid flow trends, involving four basic tasks.

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

Identifying the correspondence between stratigraphic geometries and structural setting, and fluid-flow trends is the initial step in integrating reservoir architecture and fluid-flow trends. In this step all reservoir architecture maps—including lithoisopachs, facies-distribution maps, and structure interpretations—are compared to fluid-flow maps for similarities in distribution patterns. To aid in this comparison, completion maps are needed that include all initial completions, well deepening, plug-backs, and recompletions. All salient fluid-flow directions and anomalies should be tested to determine if they can be explained by the mapped reservoir architecture. Typically fluid-flow trends are posted on maps and overlaid with geologic data to identify any correspondence.

The scenarios for determining the correspondence between reservoir architecture and fluid-flow trends are only limited by the investigator's ingenuity. Some useful scenarios include

- Comparing vertical RFT pressure depletion anomalies with genetic unit flooding surfaces
- Testing production results of plugback locations with genetic unit flooding surfaces
- Generating scenarios between production characteristics and genetic units being produced
- Mapping and comparing water encroachment levels with hypothesized compartmentalization
- Investigating and developing geologic models that explain variability in water chemistry
- Explaining variable initial oil-water contacts
- Comparing and contrasting gross sandstone isopachs with hypothesized fluid flow movement.

Design Petrophysical Models and Establish Reservoir Flow Units

Introduction

Designing petrophysical models and establishing reservoir flow units is the second task in integrating reservoir architecture and fluid-flow trends. Salient petrophysical properties include porosity, permeability, residual oil saturation, capillary pressure, formation resistivity factor, wettability, relative permeability, and initial water saturation. The goal in modeling petrophysical parameters is to devise methods for determining storage capacity, flow capacity, and hydrocarbon pore volume in a reservoir. In this task several scales of geologic attributes are tested for correlation with petrophysical parameters. Geologic attributes from microscopic pore geometry to mesoscopic facies and parasequences should be tested against both petrophysical properties measured in core and wire-line measurements for possible correlation and uniqueness in a geologically based grouping. The basic geologic attributes from smaller to larger scale include (1) pore geometry, (2) lithology, (3) facies, (4) genetic unit/subunit, and (5) formation.

The relative influence and importance of these geologic attributes are quantified at this point by applying the knowledge obtained in the previous characterization work, specifically the petrography and relationships developed between core and wire-line logs.

Petrophysical parameters are interdependent at the geologic scale. Often, however, the scale at which correlation between geologic attributes and core measured petrophysical parameter is determined is too small for application to wire-line logs. This necessitates scaling up to what can be determined from wire-line logs so that the model results can be mapped throughout the field. This log-resolvable scale also influences the flow unit scale. When petrophysical models are derived, establishment of flow units can be finished. Each flow unit established should have three characteristics: interdependent petrophysical parameters, log signature capable of correlation over extended areas of the reservoir, and fluid-flow boundaries at the top and base.

Pay Cut-Offs

Pay cut-offs determine what portion of the reservoir bulk volume will be considered as containing producible hydrocarbons. The term net pay is applied to describe that portion of the reservoir that meets the pay cut-off criteria. Numerous petrophysical attributes are applied in determining the cut-off values for net pay. Porosity-permeability cross-plots are analyzed to determine at what porosity the rock becomes too tight for hydrocarbons to flow. Capillary pressure curves are analyzed to determine at what porosity and permeability the pore throats are too small for hydrocarbons to migrate into the rock. Initial water saturation is analyzed along with relative permeability to determine at what saturation the rock becomes permeable to water and not hydrocarbons. Additionally in sandstones often a bulk volume shale value is applied as a means of distinguishing net pay.

Pay cut-offs for a reservoir are best determined on a depositional and/or diagenetic facies-by-facies basis. At the facies level, the mineralogy and rock pore geometry, and consequently the rock-fluid interaction, will be the most similar. A facies-by-facies set of cut-offs requires both a good set of core analysis and a concise geologic description of analyzed core plugs. With this pay cut-off control significant error can be reduced in the hydrocarbon volumetric calculation.

Determine the Distribution of Petrophysical Properties

Introduction

Determining the distribution of petrophysical characteristics is the third, and one of the most critical tasks in integrating reservoir architecture and fluid-flow trends. How the petrophysical characteristics are distributed must honor both the geologic architecture and fluid flow trends. A reservoir characterization model usable for analysis of reserve growth potential must be developed at the flow unit scale when spatially distributing petrophysical parameters. Both deterministic and stochastic methods are currently used in distributing the petrophysical parameters spatially. To obtain a distribution that honors both the geologic architecture and fluid-flow trends and the known data the application of deterministic and stochastic methods must be balanced.

Storage capacity, flow capacity, and hydrocarbon pore volume are the key petrophysical characteristics for which the spatial distribution is determined. Historically these parameters have been mapped; however, increasingly 3-D geocellular models are being developed. Any method that represents the petrophysical parameters' distribution must rely on a gridding system. This gridding system should be chosen with respect to the well spacing, steepness of flow unit dip, and computing power available. When drawing storage capacity, flow capacity, and hydrocarbon pore volume maps the trend of both the geologic reservoir architecture and fluid flow should be reflected as much as feasible.

3-D Geocellular Reservoir Model Development

Workflow Outline

Three-dimensional geocellular computer modeling is the latest technology applied in determining the distribution of petrophysical properties. The utility of 3-D computer geocellular modeling is inherent in the three-dimensional nature of geology. Galloway and Hobday (1983) state "Depositional systems provide meaningful sections of basin fill" and "The concept of depositional system implies 3-dimensional units." Therefore, in order to properly model a hydrocarbon reservoir the depositional system architecture must be captured in three dimensions. A properly constructed 3-D computer model combines the input of all aspects involved in reservoir characterization and results in greater precision in volumetric calculation and reservoir simulation (Fig. 14). After a model is constructed additional boundaries can be overlain, such as oil-water contacts, hypothesized reservoir compartments, and/or lease boundaries. These additional boundaries allow further zonation of a reservoir for analyzing volumetrics and reserve growth strategies. Modeling is accomplished in four tasks:

(1) Preparing petrophysical attributes for each open-hole wireline log suite

(2) Creating surface grids for each correlatable geologically distinct unit

(3) Interpolating petrophysical attributes between wells

(4) Performing geocellular operations.

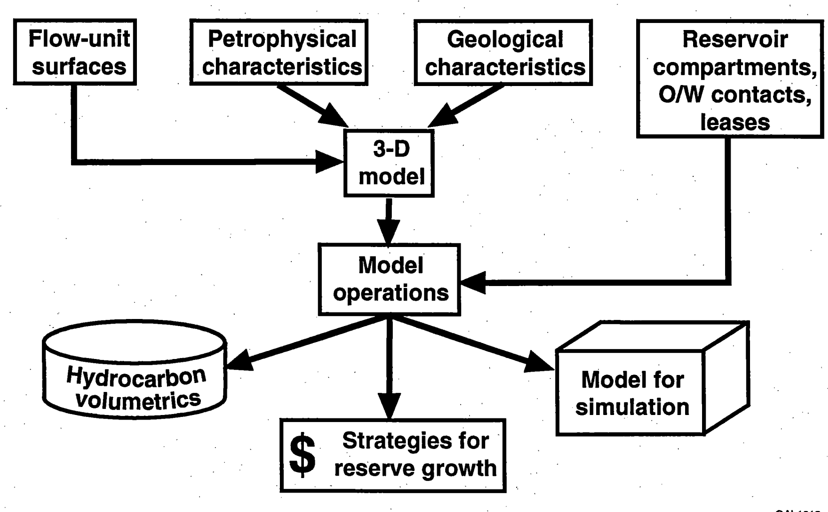


Figure 14. A properly constructed 3-D computer model combines three sets of input into the 3-D model. Performing model operations results in greater precision in volumetric calculation and is critical to developing reserve growth strategies and to reservoir simulation.

Geocellular computer modeling in 3-D allows several levels of geological control. At the mesoscopic scale, the geometry of each flow unit and their interspatial relationship are modeled. The intra-flow-unit structure is built by controlling the size cells and how they are stacked. At the cell level, attribute values are assigned cell by cell such that the final model contains a fine 3-D grid of petrophysical and geological properties.

Preparing Petrophysical Attributes for Each Open-hole Wireline Log Suite

The first step in developing a 3-D reservoir computer model is to determine petrophysical attributes for each open-hole wireline log suite. This step is accomplished through the data preparation tasks listed below.

- Determine and apply petrophysical equations
- Set the scale of data to use in the 3-D model
- Adjust data quality.

Determining and applying petrophysical equations is accomplished by wireline-core calibration and/or through the application of published models. For sandstone reservoirs typical attributes that are calculated include porosity, bulk volume of shale, and initial water saturation.

Setting the scale of petrophysical attribute data to use in the 3-D model can be accomplished in two ways. The first way is to apply some type of running average method to the data and then extract values at a set interval. The interval is set at the scale of resolution one would like to obtain from the model. The second method is to extract unaveraged samples of data from the wireline information at the scale to be modeled. These extracted values are imported into a 3-D geocellular modeling software package and are used as the wireline attribute values.

Creating Surface Grids for Each Flow Unit

The second step in building a 3-D geocellular model is to create surface grids for each flow unit. These genetic units/subunits form the basic framework for the 3-D model. There are four basic types of data that can be used to generate surface grids. Any combination may be most appropriate for modeling a given reservoir depending on the geometric relationship between flow units. Data types for surface grids can come from computer-contoured genetic unit tops, gridded 3-D seismic, digitized hand-drawn maps, or surfaces generated by summing isopach values. The choice of which geologic markers to grid depends on the scale of detail to be incorporated, the depositional system of the reservoir, and the control desired on interpolation of petrophysical attributes. The steps for generating surface grids for import into a 3-D geocellular model are:

1. Generate structure map for laterally persistent marker horizon above the reservoir interval and prepare grid
2. Generate geologic isopach of each genetic subunit below marker horizon
3. Digitize subunit isopachs and grid to honor well data
4. Add successive isopachs downward from top marker grid
5. Import grids into 3-D modeling software.

Interpolating petrophysical attributes between wells

Interpolating petrophysical properties between wells is the third step in developing a 3-D geocellular model. This step involves populating the intrawell portion of the reservoir with petrophysical properties needed to determine hydrocarbon volume, and flow capacity. Little hard information actually exists as to what the properties are or how to populate this unknown space. The basic information that drives the interpolation is analogous reservoirs with smaller well spacing, or geologic models, developed from studies of both outcrop and modern environments. Rarely, however, do these studies include hard petrophysical information. The two main methods currently being applied are deterministic and stochastic interpolation. The deterministic interpolation of petrophysical properties applied in geocellular modeling has five controls:

1. Flow-unit geometry
2. Cell search radii
3. Geologic template weighting
4. Geologic cellular layering character
5. Applied petrophysical parameter interpolation scheme.

Flow unit geometry

Flow-unit surfaces control intergenetic unit heterogeneity and constrain petrophysical attribute interpolation vertically and laterally within the flow-unit boundaries. The stacking of successive flow-unit surfaces produces three-dimensional bodies within which the petrophysical properties are interpolated. Interpolation can be terminated abruptly by the truncation of flow units onto basement highs, against faults, and/or other disconformities.

Cell search radii

The cell search radii control intragenetic unit heterogeneity by designating the data sample that is used in interpolating attribute values to cells. The attribute values assigned to a given cell are only influenced by well data within the search radii area. The search radii must be chosen such that enough well data lie within the set area such that interpolation of attributes to the cell can take place. Limiting the search radii gives the modeler the opportunity to keep data from over-influencing the between-well cell attribute values.

Geologic template weighting

Geologic template weighting allows geologic control in the interpolation of attributes within flow units. Commonly, templates are developed from gross sandstone or facies maps and can also be based on 2-D petrophysical maps such as storage capacity or flow capacity. The template is divided into areas of influence along facies boundary lines. Areas across the map that fall within the same facies type compose a "correlation facies." Cells and wells within a correlation facies will influence the attribute values assigned to other cells in the same correlation facies. They will not, however, influence cells in another correlation facies. For example, a cell that lies in an overbank correlation facies on one side of a channel can influence the overbank cells on the other side of a channel. Geologic template weighting results in a strongly deterministic interpretation built within a genetic unit or parasequence framework (Fig. 15).

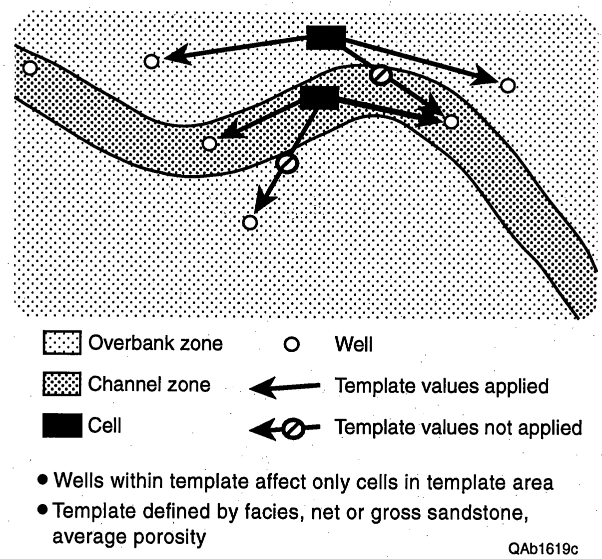


Figure 15. Geologic template weighting, which results in a strongly deterministic interpretation based on the geologic sequence stratigraphic model.

Geologic cellular layering character

Geologic cellular layering character controls the interrelationship of cells within a flow unit, thus controlling the vertical and lateral heterogeneity within the flow unit. The character of cell layering is based on the geologic interpretation of each flow unit. Common cell layering characteristics include cell dimensions, proportional layering, onlap, and truncation (Fig. 16). The 3-D grid resolution is determined by the cell dimensions. Typically a cell size is applied such that several cells will lie between wells. Proportional layering is normally applied when thickening or thinning of an individual flow unit is independent of another flow unit. Both onlap and truncation are applied when the geometries of flow units are dependent on one another. Geologic cellular layering character is therefore a critical avenue through which the geologic architecture is incorporated into the 3-D model.

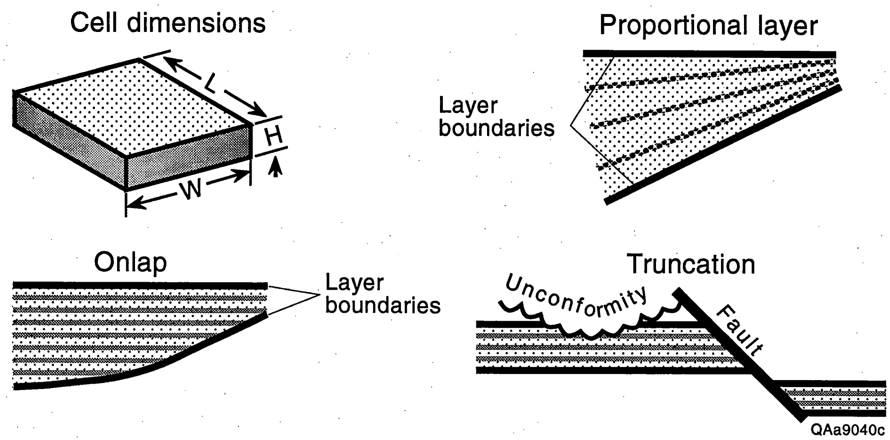


Figure 16. The character of cell layering is based on the geologic interpretation of each flow unit. Common cell layering characteristics include cell dimensions, proportional layering, onlap, and truncation.

Petrophysical Property Interpolation Schemes

Two basic attribute interpolation schemes can be applied to distribute petrophysical properties. One scheme is to apply a key attribute interpolated from the well log data to each individual cell based on the aforementioned interpolation controls. Upon interpolation of this property remaining properties are assigned to the cell as a function of the key property. The benefit of this type of interpolation scheme is that the covariance between petrophysical properties is captured. A second scheme is a multiple property model, in which all properties are interpolated independently based on the other aforementioned controls. The properties can be interpolated deterministically or stochastically. No covariant relationship is preserved; however, if data are insufficient to establish a covariant relationship, then this scheme may be necessary.

Geocellular Operations

Geocellular operations are the final step in developing a 3-D reservoir model. Several model operations such as the application of attribute model equations, geobody (attribute continuity) analysis, attribute summation maps, and hydrocarbon volumetrics are accomplished in this step.

Applying attribute model equations allows additional attributes to be assigned to each cell in the model. Hydrocarbon volumetrics are determined by applying four steps: (1) input reservoir boundary/compartmentalization map; (2) input hydrocarbon reservoir volume factor; (3) apply pay cut-offs; and (4) calculate original hydrocarbons in place.

The final task in integrating reservoir architecture and fluid-flow trends is the calculation of original and remaining hydrocarbons. Having determined the distribution of the hydrocarbon pore-volume, the hydrocarbon-in-place volume is calculated for each flow unit by applying the volumetric equation. A hierarchy of greatest initial resource evolves from this calculation, displaying the stratigraphic variation of production potential. By subtracting the current reservoir production, the volume of remaining hydrocarbons is determined. The remaining volume of hydrocarbons less the current proved producible reserves is the target for reserve growth within a reservoir.

Oil Volumetrics

Original oil in place (OOIP), or N, in stock tank barrels (STB), is calculated by applying the volumetric method. This method is the best approach when comprehensive material balance data are not available. The volumetric solution for oil reservoirs is shown in the equation below.

$$N\ (STB) = (7758)(1\text{-}Swi)(h_n)(A)(\phi)/B_{oi} \qquad (1)$$

where

S_{wi} = initial water saturation (fraction)

h_n = net pay thickness (feet)

A = reservoir area (acres)

ϕ = porosity (fraction)

B_{oi} = formation volume factor (reservoir barrels/stock tank barrels).

The original residual oil volume (N_{ro}) is calculated volumetrically (equation 2). The residual oil volume is that portion of the oil held by capillary forces such that it will not be removed by waterflood.

$$N_{ro}\ (STB) = (7758)(S_{or})(h_n)(A)(\phi)/B_{oi} \tag{2}$$

where S_{or} = residual oil saturation as a fraction of pore space.

Remaining mobile oil (RMO) is then determined by subtracting both the N_{ro} and cumulative production from the OOIP. The RMO is the target for improved primary and secondary recovery projects delineated through reservoir characterization.

Gas Volumetrics

Original gas in place (OGIP), or G, is also calculated by the volumetric method. Equation 3 represents the general solution for calculating original gas volume

$$G\ (MSCF) = (43{,}560\ Ah\phi\ (1-S_{wc})/\ B_g + R_sN)/1{,}000 \tag{3}$$

where

A	=	Reservoir area (acres)
h	=	Net pay thickness (ft)
ϕ	=	Porosity (fraction)
Swc	=	Connate water saturation (fraction)
Bg	=	Gas formation volume factor (reservoir ft^3/SCF)
Rs	=	Solution gas oil ratio (SCF/STB)
N	=	Original oil in place (STB)

Except in retrograde gas condensate or associated gas reservoirs, the term R_sN is zero. The gas formation volume factor, Bg, is given by equation 4 (Smith, 1983).

$$Bg = (P_{sc}Z_{res}T_{res})/\ (T_{sc}P_{res})\ (\text{reservoir } ft^3/SCF) \tag{4}$$

where

P_{sc}	=	Pressure at standard condition, 14.7 psi
T_{sc}	=	Temperature at standard condition, 60° F
P_{res}	=	Reservoir pressure (psi)
T_{res}	=	Reservoir temperature (°F)
Z_{res}	=	Gas compressibility factor reservoir condition.

The gas compressibility factor, Z, is a function of the fluid composition and reservoir temperature and pressure. The Z factor can be calculated as a function of pseudo-reduced temperature and pressure of the reservoir gases. The methodology of Brill and Beggs (1974) was applied in this resource assessment and is shown in equation 5:

$$Z = A + (1-A)/e^{B} + C\,(P_{pr})^{D} \tag{5}$$

where

$A = 1.39(T_{pr} - 0.92)^{0.5} - 0.36T_{pr} - 0.101$

$B = (0.62 - 0.23T_{pr})P_{pr} + [0.066/(T_{pr} - 0.86) - 0.037]\,(P_{pr})^2$

$+ 0.32(P_{pr})^6/10^{9(T_{pr} - 1)}$

$C = 0.132 - 0.32 \log T_{pr}$

$D = \text{antilog}(0.3106 - 0.49T_{pr} + 0.1824(T_{pr})^2)$

$T_{pr} = T_{res}/T_{pc}$, Pseudo-reduced temperature

$P_{pr} = P_{res}/P_{pc}$, Pseudo-reduced pressure

P_{pc} (T_{pc}) = Pseudo-critical pressure (temperature).

To calculate pseudo-reduced pressure and temperatures it is necessary to calculate the pseudo-critical temperature and pressure of the gas. The most accurate method to calculate the pseudo-critical pressure and temperature is to use gas composition. But since the composition is not readily available, an indirect method of estimating these parameters from the reservoir gas gravity is used. The correlations of Brown and others (1948) shown in equations (6) through (9) are used to estimate these parameters. The surface, or "California," gas curves are fit by the equations

$$P_{pc} = 677 + 15.0\,g_r - 37.5\,(g_r)^2 \tag{6}$$

$$T_{pc} = 168 + 325\,g_r - 12.5\,(g_r)^2 \tag{7}$$

and the "condensate" gas curves, have the following relationship:

$$P_{pc} = 706 - 51.7\,g_r - 11.1\,(g_r)^2 \tag{8}$$

$$T_{pc} = 187 + 330\,g_r - 71.5\,(g_r)^2 \tag{9}$$

where

g_r = gas gravity = ratio of gas and air densities at standard conditions.

Application of these equations allows the estimation of gas compressibility and thus the volume of gas in each reservoir. The volume of remaining gas is then determined by subtracting the reservoir cumulative production from the calculated OGIP.

Identify Reserve Growth Potential

Introduction

Identifying reserve growth potential is the fourth and final step in reservoir characterization. Reserve growth potential is identified by critically analyzing the reservoir characterization model developed from integrating reservoir architecture and fluid-flow trends. The identification of reserve growth requires four consecutive tasks (Fig. 17). Calculation of current hydrocarbon reserves is the first task. The results of reserve analysis are applied, along with the calculated original hydrocarbons in place, to delineate the remaining hydrocarbon resource. Reserve-growth concepts are then generated by synergistically analyzing the remaining hydrocarbon resource within the context of the reservoir model. The final task is to target reserve-growth opportunities by applying the reserve growth concepts.

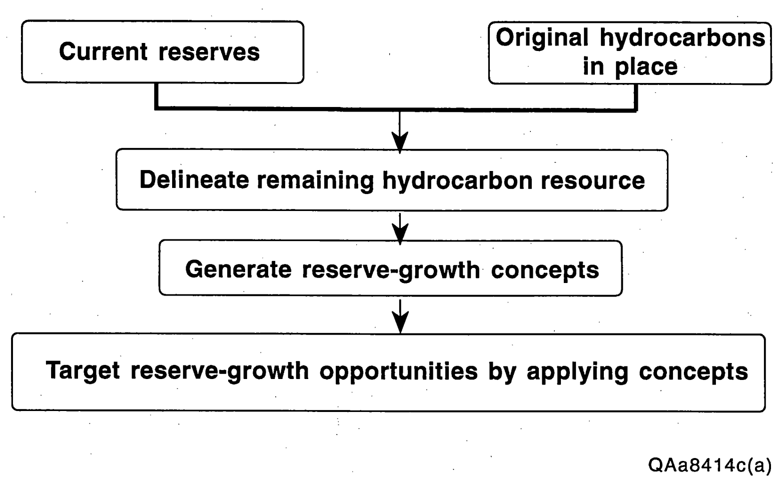


Figure 17. Identifying reserve growth potential involves four tasks.

Calculation of Hydrocarbon Reserves

Character of Reserves

Evaluators of hydrocarbon resources constantly strive to improve the approaches used to describe and quantify reserves. The problems addressed in this pursuit are twofold. The first hurdle concerns the interplay of the multiple factors that influence producibility of hydrocarbons. These factors are scientific uncertainty, technology, and socioeconomics. The second difficulty results from the tendency of these factors to change through time. This dynamic nature causes reserve values to span a continuum of possibilities. To better grasp the significance of reserve variability we attempt to superimpose a categorical scheme. Categorization is a normal scientific endeavor, but it is difficult to apply in practice because reserve values are a continuum.

Reserve Nomenclature and Variability

The commonly accepted nomenclature for categorizing reserves was discussed by Cronquist (1991). He noted that the categorization scheme of "proved," "probable," and "possible" reserves, which is in common use worldwide, is extremely subjective, and the confidence implied by these terms may differ according to the definition and methods used to make the determinations. Thus, the utility of this system is limited. Ideally, reserve nomenclature should communicate the same certainty of reserve values. The qualitative reserve definitions are an attempt to pass on the confidence level of how scientific uncertainty, technology, and socioeconomics will affect a derived reserve value. Probabilistic methods have been suggested as a method to quantify the reserve variability due to scientific uncertainty (Cronquist, 1991). The inherent weakness in probability is that little is known about the probability distributions of the engineering parameters used to calculate reserves. Therefore, the need exists to explore the probability character of these engineering parameters within a geologic context.

The evaluation of scientific uncertainty in reserve calculations has led to many studies of the controls on recovery efficiency. An American Petroleum Institute (API) study (1967) concluded that the initial reservoir drive mechanism affects recovery efficiency. Arps (1970) established a relationship between recovery efficiency and oil in place, oil mobility, water saturation, and pressure drop. Another API study (1984) recognized a relationship between reservoir recovery efficiency and geographic area, lithology, and drive mechanism. Tyler and others (1984) demonstrated that oil reservoir recovery efficiency is largely controlled by reservoir genesis and initial drive mechanism. Together these studies identify a large number of geologic and engineering attributes that affect recovery efficiency and thus must be incorporated in RVP analysis.

Technology and socioeconomic factors also affect the variability of reserve estimates. Although socioeconomic influences, such as oil price and taxes, are often predicted, their direct effects on reserve calculations vary from operator to operator. In the absence of socioeconomic influences, the influence of technology on reserve values is dependent on the geologic and engineering character of a reservoir. Within the context of a given reservoir type, or geologic play, certain reservoir developmental strategies will have greater impact on recovery efficiency than others.

Calculation of Volumes of Reserves

The calculation of hydrocarbon reserves is derived from production performance analysis. The type of production performance analysis applied in a given circumstance is dependent on the data available and the constraints of time and manpower. Reserves are determined by the following four methods:

- Analogy through applying recovery factors
- Empirically from decline curve analysis
- Material balance
- Reservoir simulation.

Upon determination of reserves the volume of remaining hydrocarbons is calculated by subtracting the ultimate recovery from original hydrocarbons in place. The remaining hydrocarbons in place are determined at various scales, from field scale to flow unit scale, and used as a tool in targeting reserve growth potential.

Delineation of Remaining Hydrocarbon Resource

Delineation of remaining hydrocarbon resource requires understanding the spatial residency of the remaining hydrocarbons. At the largest scale (reservoir level) remaining mobile oil, residual oil, and remaining gas can be determined, identifying a first level of feasibility for reserve growth. At the next finest scale, separate flow unit hydrocarbon volumetrics are calculated, initiating the process of targeting specific opportunities. For each flow unit, maps of remaining hydrocarbons in place, remaining mobile oil, and apparent area drained are generated to further delineate targets of reserve growth potential. These maps result in a specific picture of where the remaining hydrocarbons reside.

Generate Reserve-Growth Concepts

Reserve growth in already-discovered reservoirs comes from two sources. When additional or improved reservoir management is applied to a reservoir the recovery efficiency can be increased, resulting in reserve growth. This source does not delineate new hydrocarbons but does a better job at obtaining what is known. The second source of reserve growth comes from the discovery of additional oil within the already discovered field. This source of reserve growth is often a result of recharacterizing an old reservoir in a new way.

Improved reservoir management results in reserve growth by enhancing production performance and thus improving recovery efficiency. Increased recovery efficiency is achieved by applying advanced recovery techniques such as improved pump design, well stimulation, implementation of optimized advanced secondary and tertiary recovery strategies, and infill drilling. All of these techniques must be applied in conjunction with detailed engineering and geologic reservoir characterization if production performance is to be optimized. Proper pump design focuses on inflow performance. Well stimulation methods are employed to correct wellbore damage by reducing skin effects and can also result in improved connection of the well bore to isolated, compartmentalized oil. Advanced secondary and tertiary recovery development methods increase recovery efficiency by adding energy to the reservoir and by reducing rock-oil interfacial tension, thus reducing residual oil saturation. Infill drilling can increase the vertical and aerial sweep efficiency during both advanced secondary and tertiary recovery by increasing interwell pay continuity, by redefining flooding patterns, and by contacting isolated, compartmentalized oil. Reserve growth through improved reservoir management can also arise through the recognition of

- fault-controlled untapped compartments
- stratigraphically and/or diagenetically controlled untapped compartments
- updip attic oil and/or gas
- incompletely drained infill locations
- bypassed mobile oil.

Reservoir reexploration is the second process that stimulates reserve growth. The major components of reexploration are (1) offstructure step-out extension drilling and (2) deepening and recompletion of missed zones in existing wells. Extension drilling is typically undertaken when geological and engineering analysis indicates the potential for extending the reservoir's limits. Such drilling is usually the result of redefinition of reservoir structure, the position of the oil-water contact, or vertical or lateral limits of effective porosity. This is commonly the case when the trapping mechanism is recognized as being partly stratigraphic instead of wholly structural. Reinterpretations are typically based on analysis of production data, geological characterization, new technology, or changes in economic factors. Deepening of existing wells can also result from reinterpretation of reservoir structure and geometry, or may be driven by price change alone. Recompletion of missed zones can occur when reinterpretation of well logs or correlation from a nearby producing well indicates missed pay.

Target Reserve-Growth Opportunities

Target Zones Containing Poorly Drained Hydrocarbons

Major targets for reserve growth are portions of a producing reservoir that will remain poorly drained under the current producing practice. Determination of the spatial residence of the remaining hydrocarbon resource is analyzed on a flow unit basis. At the flow unit level, tools useful in determining reserve growth targets include

- apparent area drained maps
- remaining oil or gas maps
- remaining mobile oil maps.

These types of flow-unit-scale maps highlight poorly drained portions of a reservoir as a result of areas that appear to be undrained and areas where significant remaining hydrocarbons reside. Overlaying these maps with structure and depositional facies interpretations can also illustrate potential for extension and infill well drilling.

Target Zones Containing Uncontacted Hydrocarbons

A second target for reserve growth is zones from which no production has occurred in the past. These are zones where no perforations have been open to potentially drain the hydrocarbons. This occurs as behind-pipe unperforated pay, as zones deeper than a wellbore has penetrated, and as zones not penetrated because they occur between currently drilled wells. To assess the potential for uncontacted reserve growth the following tools are applied:

- completion zone/reservoir quality maps
- well depth penetrated map
- annotated cross sections.

A completion zone/reservoir quality map displays spatially where in a flow unit the productive hydrocarbon pore volume was initially located compared to if that zone was perforated. Areas with productive reservoir quality but that have not been perforated are potential reserve growth targets. The well depth penetrated map and annotated cross sections illustrate the potential for reserve growth from deepening wells. Correlation between wells can often indicate that a productive stratigraphic unit in one well has not been penetrated throughout a large areal extent by any other wells. Cross sections can also illustrate potentially productive intrawell zones that have not been contacted by a well.

Risk Assessing Reserve-Growth Targets

The last task in reservoir characterization is to determine which of the reserve growth targets delineated should be acted upon first. This decision requires understanding the risk involved with each target. The risk can be assessed both qualitatively and quantitatively. By the time a reservoir characterization team progresses to delineating reserve growth targets, they have a quantitative understanding as to which reserve growth concepts are the most and least risky. This understanding can be used to rank targets into hierarchy of least to most risky. Doing so will increase the success ratio and economic viability of a redevelopment program.

Quantitative risk analysis is an important part of choosing the most lucrative reserve growth target. Risk assessment decision trees are one useful way in which to approach a quantitative risk analysis. Upon constructing a risked decision tree for each reserve growth target, an expected target value is calculated. The expected values are normalized to account for risk and therefore can be directly compared to determine which target is the most lucrative.

Stochastic simulation also leads to a risk assessment of additional oil and gas potential in a reservoir. The volume of the remaining mobile oil resource is derived directly from the difference between the volume of estimated OOIP and the volumes of produced oil and estimated residual (immobile) oil. The accuracy of these estimates is dependent on the values of each of the geologic parameters that go into the hydrocarbon volumetric equations, namely initial water saturation, residual oil saturation, porosity, net thickness, and area of the reservoir. In past standard practice, each of these reservoir attributes was characterized by a deterministic mean value. These mean values are substituted into the reserve equation to calculate OOIP volumes that form the basis for subsequent estimates of remaining mobile oil volumes and further production potential. The heterogeneity of most reservoir rocks suggests that using single values to describe reservoir attributes is inadequate. Modern reservoir characterization studies should attempt to more accurately describe reservoirs by incorporating heterogeneity and attempting to quantify the variability of reservoir units. This is accomplished by identifying not only mean values of reservoir attributes but also the range and distribution of these values.

Risk analysis techniques are now commonly used to help identify and minimize the uncertainty inherent in hydrocarbon exploration and development. The area sampled by a typical oil well drilled with an 8-inch-diameter hole on a 40-acre sample spacing represents only 10^{-6} percent of the entire reservoir area. This small sample of reservoir attributes creates substantial uncertainty concerning reservoir description. In field development, constraining the level of this uncertainty is fundamental to good resource evaluation and reserve growth potential assessment. Risk analysis attempts to balance the uncertainty against the risk. As generally defined, risk reflects the range or dispersion of possible outcomes of a particular event (for example, if the outcome can be predicted with 100-percent confidence, there is no risk). In hydrocarbon field development, risk may be defined as the variability in values for a given reservoir parameter that has an effect on hydrocarbon storage. Uncertainty refers to an event having unknown outcomes or outcomes that have unknown associated probabilities of occurrence. Quantifying the variability of possible outcomes (in our case the variability of reservoir attribute values) so that the probability of occurrence is understood reduces the uncertainty associated with predicting what will actually be encountered. This may be achieved by identifying the probability distribution function that describes the range of possible values. Our goal in detailed reservoir characterization is to identify, through rigorous statistical analysis, the range and probability distributions that best describe individual reservoir attributes. These results may then be incorporated in hydrocarbon volume calculations to generate more accurate estimates of OOIP and remaining oil resource potential, which should in turn reduce the risks and costs associated with additional field development.

Methodology of Volumetric Risk Assessment

Descriptive and central-tendency statistics are the initial step to undertake for each of the engineering parameters that influence calculation of hydrocarbon volume. These parameters include average porosity, initial water saturation, residual oil saturation, net pay, and reservoir size. Covariance is tested between each combination of parameters, and statistical F and t tests are applied in an analysis of variance (ANOVA) in order to identify statistical differences or similarities between data population subsets.

Each of the engineering parameters is analyzed to determine what type of probability function best represents the data distribution. Three best-fit tests, the chi-square, Kolmogrov-Smirnov (K-S), and Anderson-Darling (A-D) (Lindgren, 1976), can be applied, as well as visual inspection of the graphical outputs of the data. These data types should be treated as nondiscrete.

Stochastic modeling is now applied to combine the best representative probability functions. The general model is graphically represented in Figure 18. Monte Carlo and Latin Hypercube simulation methods are the most widely used. Upon seeding the simulation and setting the number of iterations a run is initiated. The result is a continuum of hydrocarbon resource volumes that represent a probability of occurrence distribution. This distribution is used to examine the possibility of reserve growth.

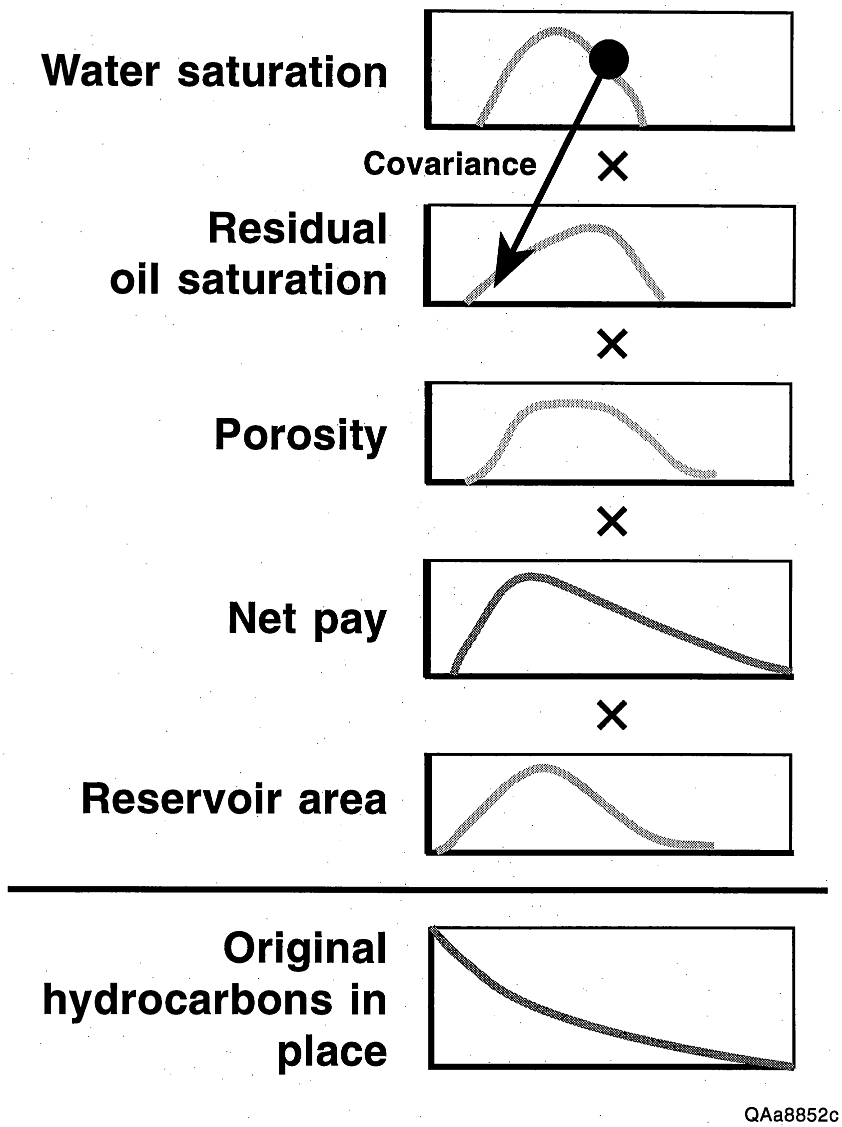


Figure 18. Stochastic modeling combines the best representative probability functions into resultant risk-adjusted hydrocarbons in place volumes.

RESERVOIR CHARACTERIZATION OF RINCON FIELD

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

Introduction

Stratigraphic compartmentalization is inherent in fluvial-deltaic depositional systems and is responsible for the incomplete and inefficient recovery of available oil and gas resources. The identification and production of incremental mobile oil resources depend on identifying which parts of the reservoir have not been effectively contacted or swept because of heterogeneity and the resultant reservoir compartmentalization. Successful advanced recovery approaches in fluvial-deltaic reservoirs depend on reservoir characterization strategies that integrate geological facies models with engineering assessments of reservoir behavior and production histories.

Location and Geologic Setting of Rincon Field

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. 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, and is limited to productive reservoir sandstones within the Frio section (Fig. 19).

The general structure in the shallow Frio section at Rincon is characterized by a northeast-trending, downthrown asymmetric rollover anticline that plunges gently to the northeast and is bounded to the west by the Sam Fordyce/Vanderbilt Fault, a major growth fault associated with the large Vicksburg Fault Zone system (Fig. 20). 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.

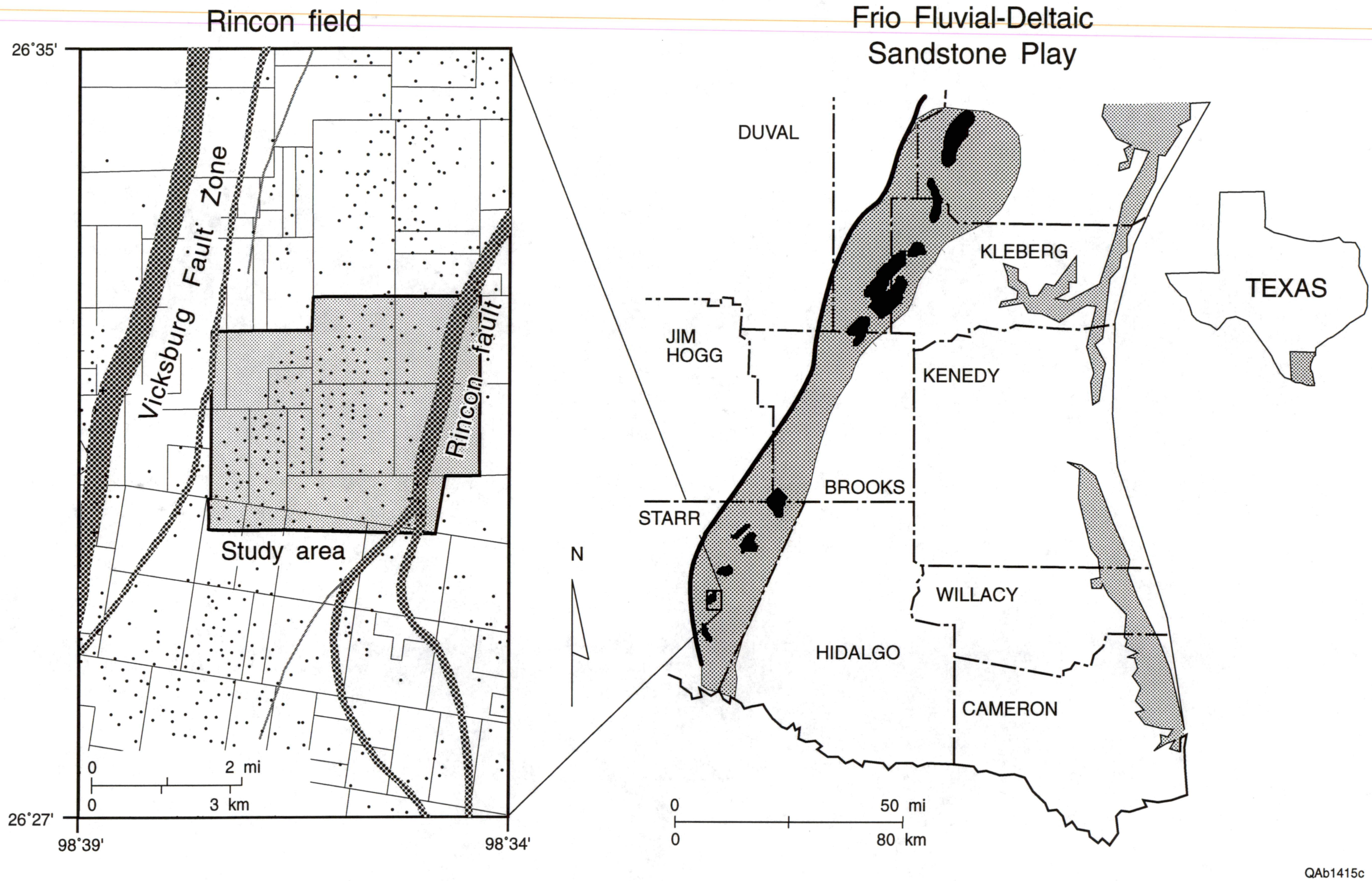


Figure 19. Location map of Rincon field within the Frio Fluvial-Deltaic Sandstone Play and area of field selected for detailed reservoir studies.

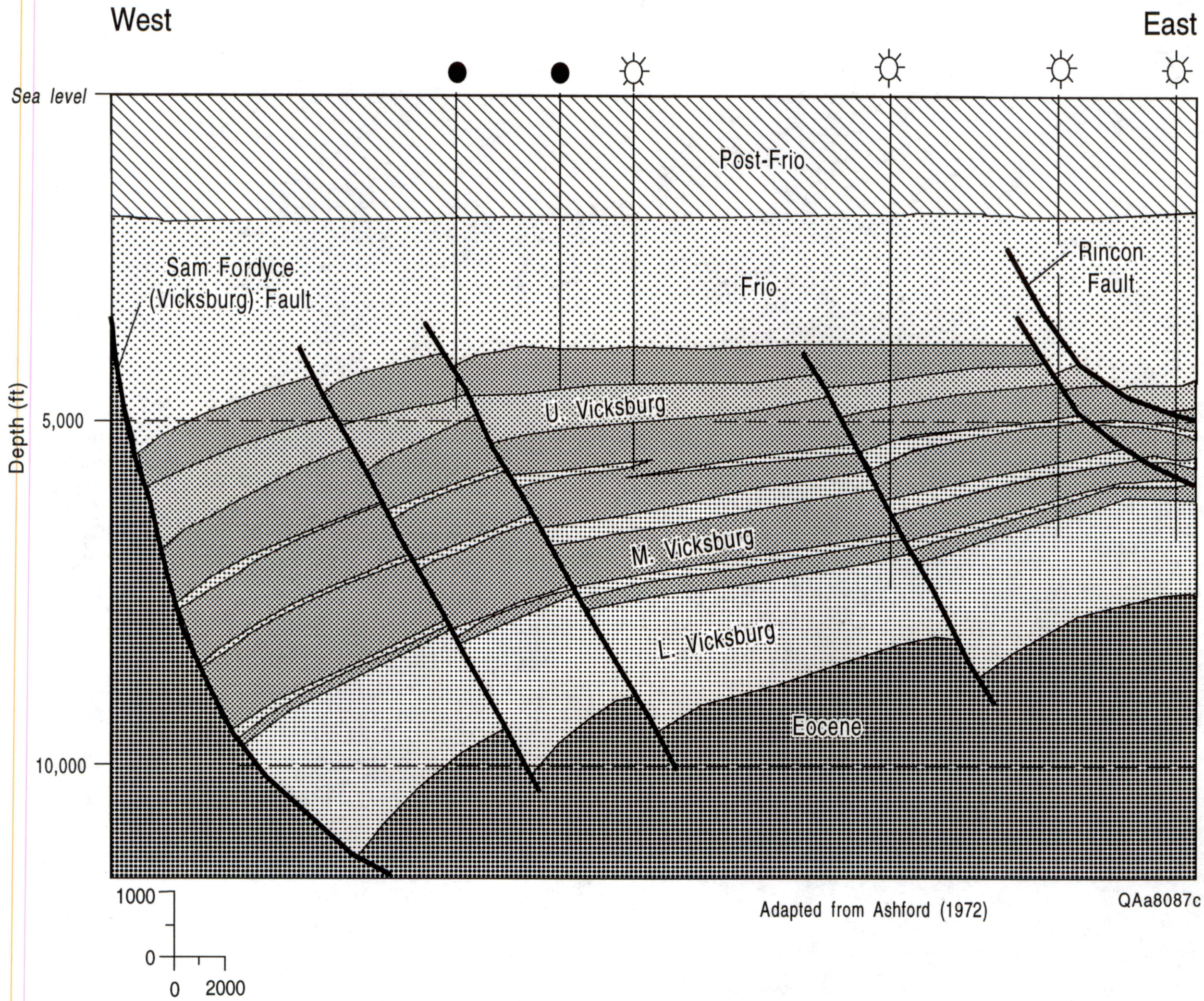


Figure 20. Generalized west-to-east cross section through Rincon field illustrating structural setting of a representative field in the Frio Fluvial-Deltaic Sandstone Play (adapted from Ashford, 1972).

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. In this project our Rincon field study focused on two reservoirs as type examples.

Reservoir Characterization Methodology

The reservoir characterization methodology applied in studying the Rincon field has been described in detail in the previous section. As part of our overall project we have developed a reservoir characterization process. The process takes a systems approach, viewing geologic and engineering data inputs with a goal of determining reserve growth potential. As with all field studies the comprehensiveness is dependent on the available data, and therefore the Rincon work covers only a subset of the total methodology developed.

Determine Reservoir Architecture

Importance of the Genetic Sequence Analysis Approach

The development of a detailed regional stratigraphic and structural context for a reservoir is a critical step in evaluating its potential for secondary hydrocarbon recovery. Sequence-stratigraphic concepts provide a chronostratigraphic framework in reservoir studies that is useful in delineating the structure of reservoir flow units and also provide a means of transporting results of reservoir studies to other fields in analogous stratigraphic settings. Construction of a reservoir framework at the sequence and parasequence scales provides a means for the natural packaging of strata into genetic units that correlate well to petrophysically defined units at the interwell scale (Tyler and others, 1992). Definition of lithologic and diagenetic reservoir flow-unit architecture of fluvial-deltaic sandstones within the context of a well-defined sequence-stratigraphic framework can provide a model to predict the distribution and continuity of permeable zones in other reservoirs deposited in analogous depositional settings. Previous detailed work on the regional geology of the Frio depositional sequence in South Texas

(Galloway and others, 1982; Galloway, 1977, 1982, 1989a, 1989b) and several recent reservoir characterization studies of Frio gas reservoirs (Jirik, 1990; Kerr, 1990; Kerr and Jirik, 1990; Kerr and others, 1992; Grigsby and Kerr, 1993) provide an excellent context in which to study individual facies components of oil-bearing reservoirs in the Fluvial-Deltaic Sandstone play.

In Rincon field, a prominent low-resistivity marker interpreted to be an important flooding surface separates the thicker, generally upward-coarsening progradational units in the lower Frio third-order unit from thinner, dominantly aggradational channel deposition in the middle Frio section. The majority of Frio production at Rincon occurs within a 1,000-ft interval of interstratified sandstones and mudstones. Laterally persistent low-resistivity surfaces interpreted to represent floodplain or interdeltaic mudstones separate primary reservoir sandstone zones that are commonly 50 to 150 ft thick. These fourth-order reservoir zones are, in turn, composed of several individual, 5–30-ft thick channel-fill units (Fig. 21). The major cause of stratigraphic complexity and compartmentalization of hydrocarbons in these sandstones is their variability in geometry and the multilateral and multistacked nature of individual fifth-order reservoir units. Fourth-order reservoir units at Rincon field were evaluated to identify specific reservoir styles that are representative of those observed throughout the play. Understanding the specific stratigraphic context of the reservoirs selected for study will facilitate the transfer of results of this study to other reservoirs, other fields, and other analogs beyond the Frio in South Texas.

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

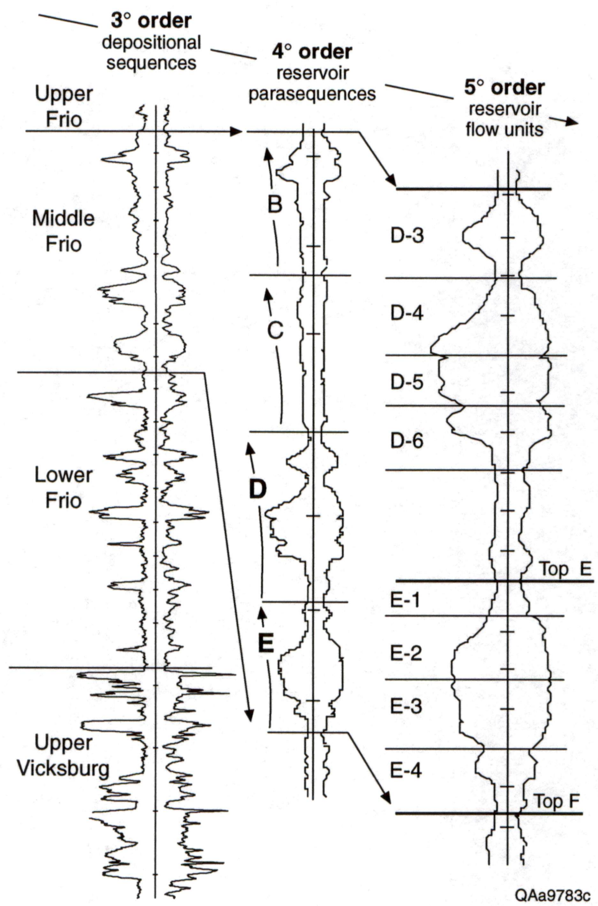


Figure 21. Spontaneous Potential/resistivity type logs illustrating (a) the general depositional sequence for the productive Frio–upper Vicksburg reservoir interval, (b) the stratigraphic context of the middle Frio reservoir sequence in Rincon field, and (c) the reservoir nomenclature of individual producing units within the Frio D–E interval selected for detailed study.

Ascertaining Internal Reservoir Stratigraphy

Regional Stratigraphy

A typical log from the productive reservoir interval in Rincon field is shown in Figure 22. The F shale marker represents the division between lower and middle Frio reservoirs, as it is located where a change in sedimentation style occurs from deposition of net progradational sandstone packages to primarily aggradational sand deposition. Reservoirs in the middle and lower Frio sections consist of multiple stacked pay sandstones. Interpretations supported by SP log profiles and whole core studies indicate that the dominant reservoir lithofacies are fluvial channel-fill deposits. Individual reservoir sandstones (fifth-order units) within each zone are commonly 5–30-ft-thick channel-fill units and have lateral dimensions ranging from 1,000 to more than 6,000 ft. The major cause of reservoir complexity and compartmentalization of hydrocarbons is a result of this variability in sandstone geometry and the multilateral and multistacked nature of these individual reservoir units. Characteristics specific to each stratigraphic reservoir interval are discussed in more detail below.

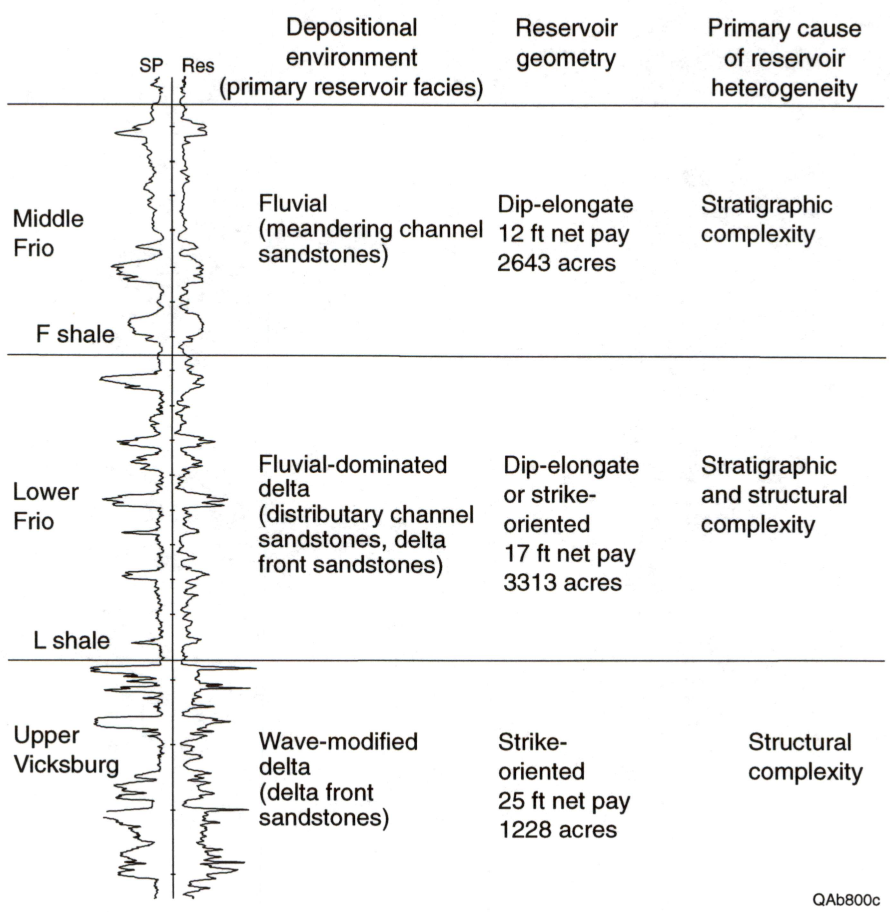


Figure 22. Depositional systems and reservoir attributes of the Rincon field reservoir section.

Upper Vicksburg reservoirs

Vicksburg reservoirs in Rincon field include the sandstone unit below the L shale shown in the lower portion of the log interval illustrated in Figure 22. These reservoirs consist of thick progradational (seaward-stepping) deltaic sandstone deposits that occur in packages 50 to 150 ft thick and are separated by 50- to 200-ft-thick intervals of mudstone. Primary reservoir facies are channel-mouth-bar sandstones that are interbedded with prodelta mudstone and siltstone. Individual upward-coarsening channel-mouth-bar deposits are generally less than 50 ft thick and stack to produce repetitive cycles that can reach 150 to 200 ft in thickness.

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

Lower Frio reservoirs

In Rincon field, the Lower Frio stratigraphic interval appears to represent deposition in an aggradational to mixed aggradational and progradational setting within the Gueydan fluvial system. The lower Frio reservoir interval shown in the log in Figure 22 is interpreted to correspond to an interval of mixed progradational and aggradational sedimentation. The F shale is taken to mark the boundary between the mixed aggradational and progradational reservoirs in the lower Frio section and the purely aggradational deposition that characterizes the middle Frio section.

Reservoir facies in the lower Frio interval are interpreted to represent predominantly fluvial channel and delta-plain distributary-channel sandstones. Channel units are distributed as elongate, dip-parallel belts. Individual, upward-fining channel sandstone packages, as evidenced by bell-shaped SP log profiles, range from 5 to 20 ft thick, and commonly stack to produce amalgamated units that have vertical thicknesses of 10 to 50 ft. These stacked sandstone packages commonly display an upward-thickening trend. Although sandstone units are, on average, thicker than in middle Frio reservoir zones, sandstone body continuity is generally less than in middle Frio fluvial channels. This may be because distributary channel-fill sandstones are commonly narrower and are flanked laterally by 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 depositional pattern in the middle Frio interval in Rincon field is characterized by sedimentation dominated by fluvial aggradation. Deposition in dip-elongate channel systems developed across the low-relief Oligocene Gulf Coastal Plain toward the shoreline in a direction from northwest to southeast (Fig. 23). Middle Frio reservoir facies consist primarily of dip-elongate fluvial channel-fill sandstones and are separated by nonreservoir facies that include levee siltstones and floodplain mudstones. Productive middle Frio reservoirs in Rincon field occur both as individual narrow channel-fill units isolated vertically and laterally by low-permeability overbank and floodplain facies and as large channel complexes with multiple sandstone lobes. Sandstones have individual thicknesses ranging from 5 to 30 ft but are commonly stacked into composite units with gross thicknesses between 20 and 60 ft. Low-permeability subfacies within the channel fill are responsible for the development of multiple reservoir compartments that may represent significant opportunities for additional recovery.

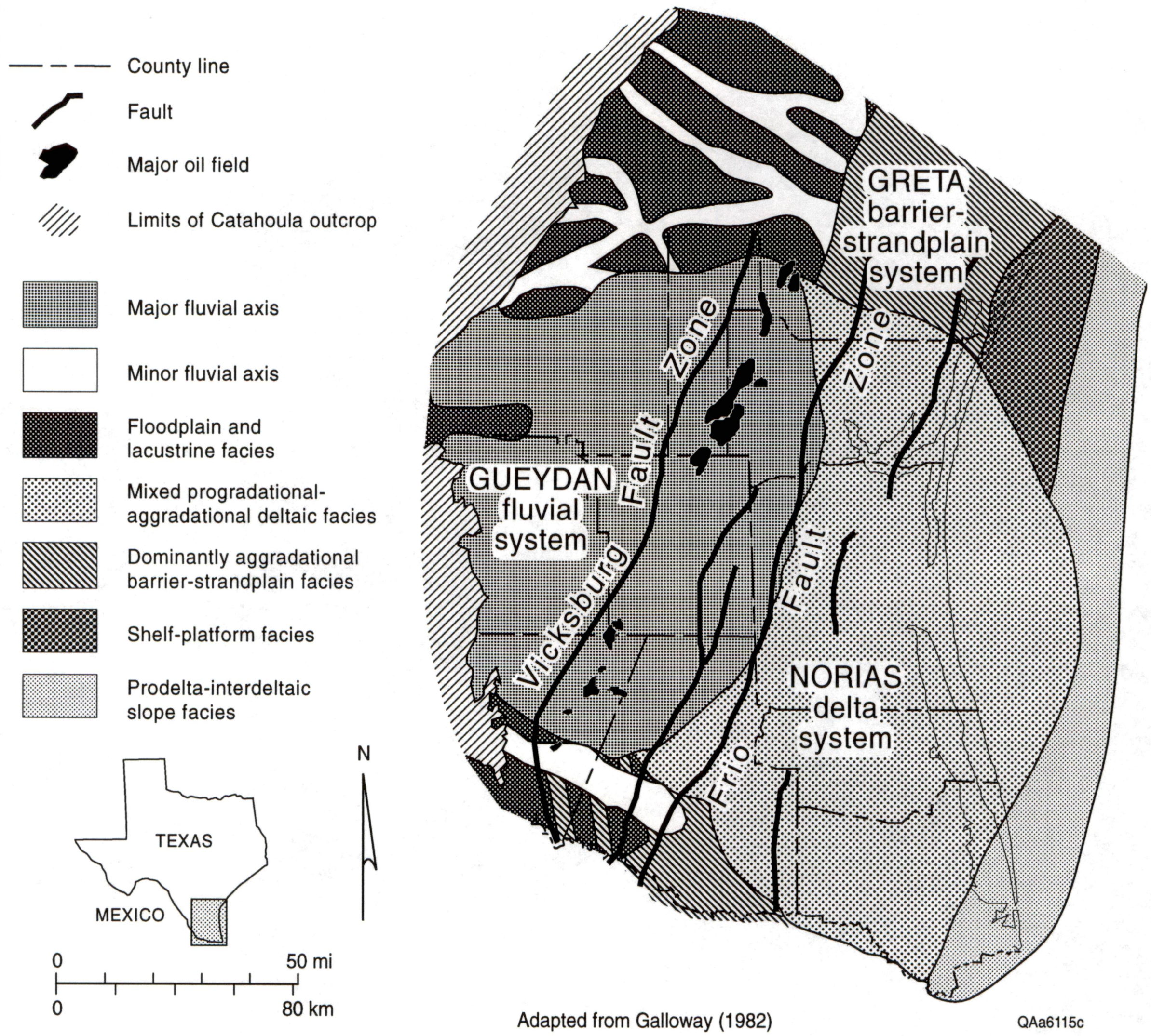


Figure 23. General distribution of the Norias delta and Gueydan fluvial depositional systems responsible for deposition of the Frio stratigraphic unit. The Frio sediments in the vicinity of the Vicksburg Fault Zone were primarily deposited in moderate- to high-sinuosity mixed-load stream environments of the Gueydan fluvial system. (Map distribution from Galloway and others, 1982.)

Description of lithofacies from core

Detailed core studies were conducted on conventional core cut from the T. B. Slick A133 and A149 wells, located in lease block 231 near the center of the field study area. A total of 155 ft of core was examined. Core descriptions from both wells, along with porosity and permeability profiles derived from conventional core analysis data, are illustrated in Figures 24, 25, and 26. Detailed core description and sampling were limited to the Frio D and E reservoirs.

The core from well 149 includes the stratigraphic interval through most of the E reservoir zone, and the well 133 core represents the depth interval through the D reservoir and the top portion of the E reservoir. Based on core observations, there are no obvious distinctive differences in sandstone mineralogy, textures, or facies types between the Frio D and E reservoir zones. Vertical facies sequences of channel-fill sandstones, splay sandstones, and floodplain mudstone units recognized in both cores support our interpretations of fluvial depositional environments determined from electric log correlations and reservoir mapping.

Mudstones

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

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

Some floodplain mudstones are green-gray and possess a mottled waxy texture typical of an altered bentonite (e.g., 3,960–3,961 ft, Fig. 24). Volcanic activity was occurring in northeastern Mexico throughout the Oligocene, and other workers have noted the presence of bentonites and high concentrations of volcanic glass in the Frio reservoir section in other South Texas fields (Kerr and Jirik, 1990; Grigsby and Kerr, 1993).

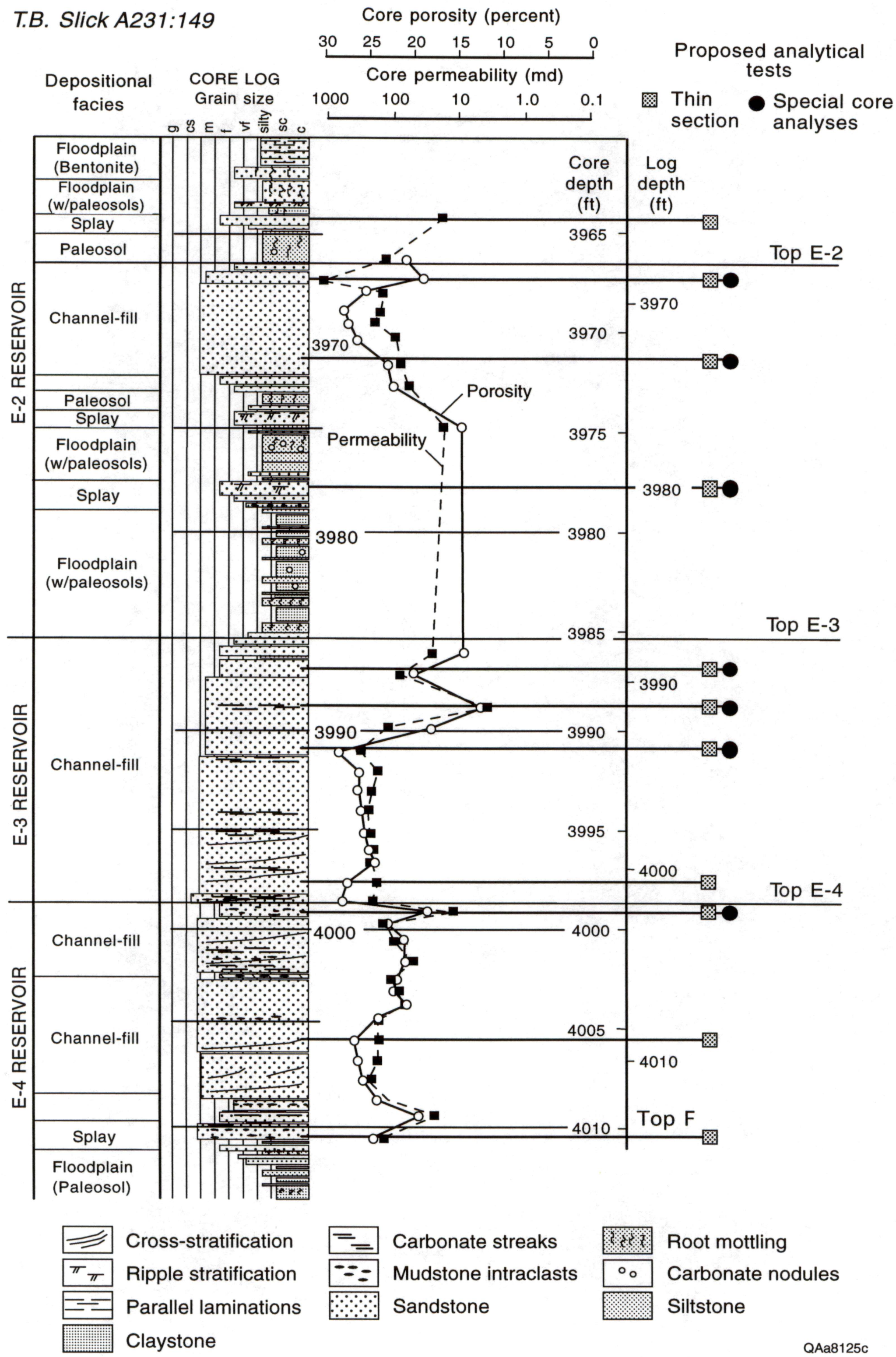


Figure 24. Graphic core log, T. B. Slick 231:149 well, Frio E reservoir zone, along with corresponding facies interpretations, core analysis data for porosity and permeability, and location of samples selected for petrographic and special core analyses.

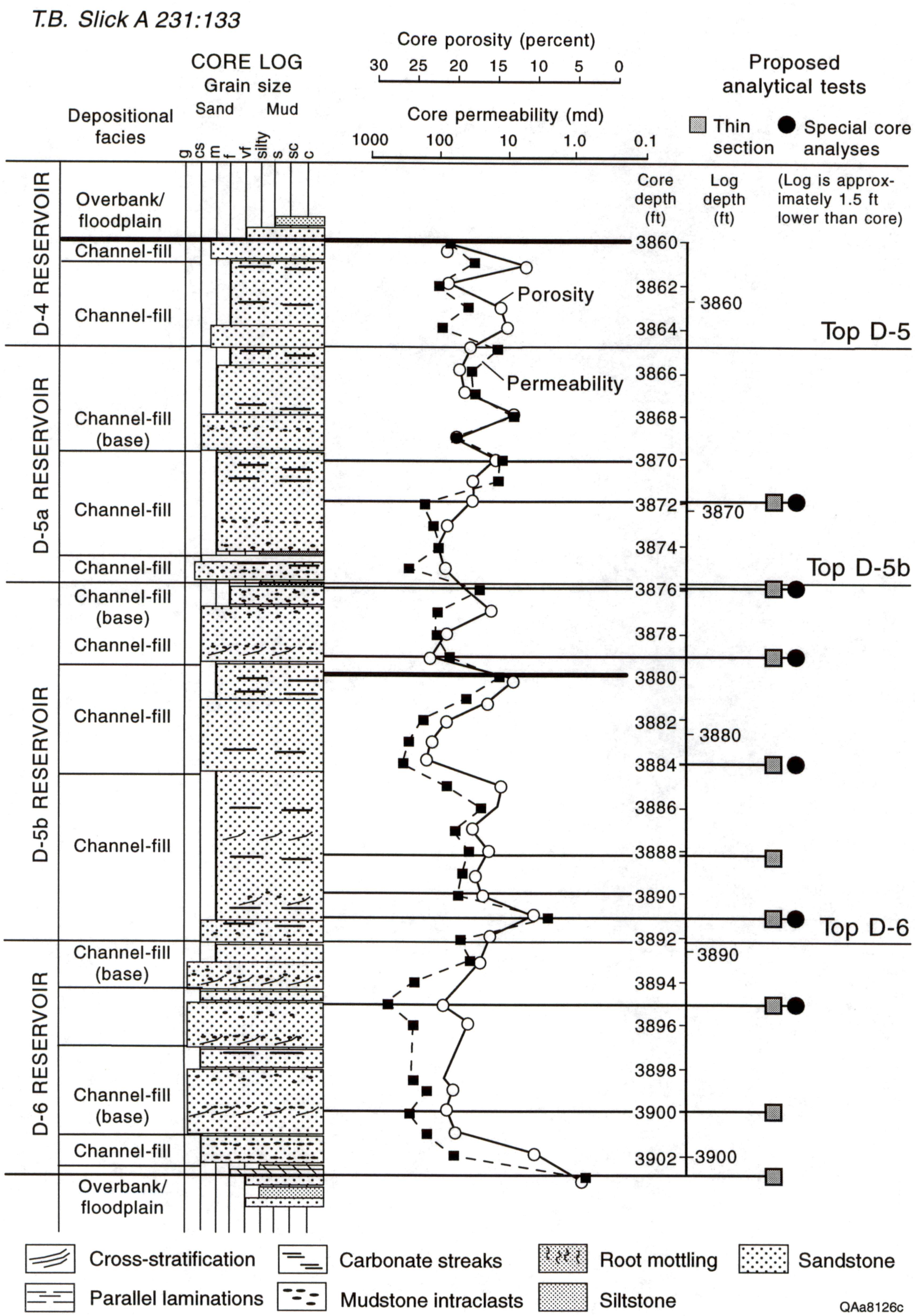


Figure 25. Graphic core log, T. B. Slick 231:133 well, Frio D reservoir zone, along with corresponding facies interpretations, core analysis data for porosity and permeability, and location of samples selected for petrographic and special core analyses.

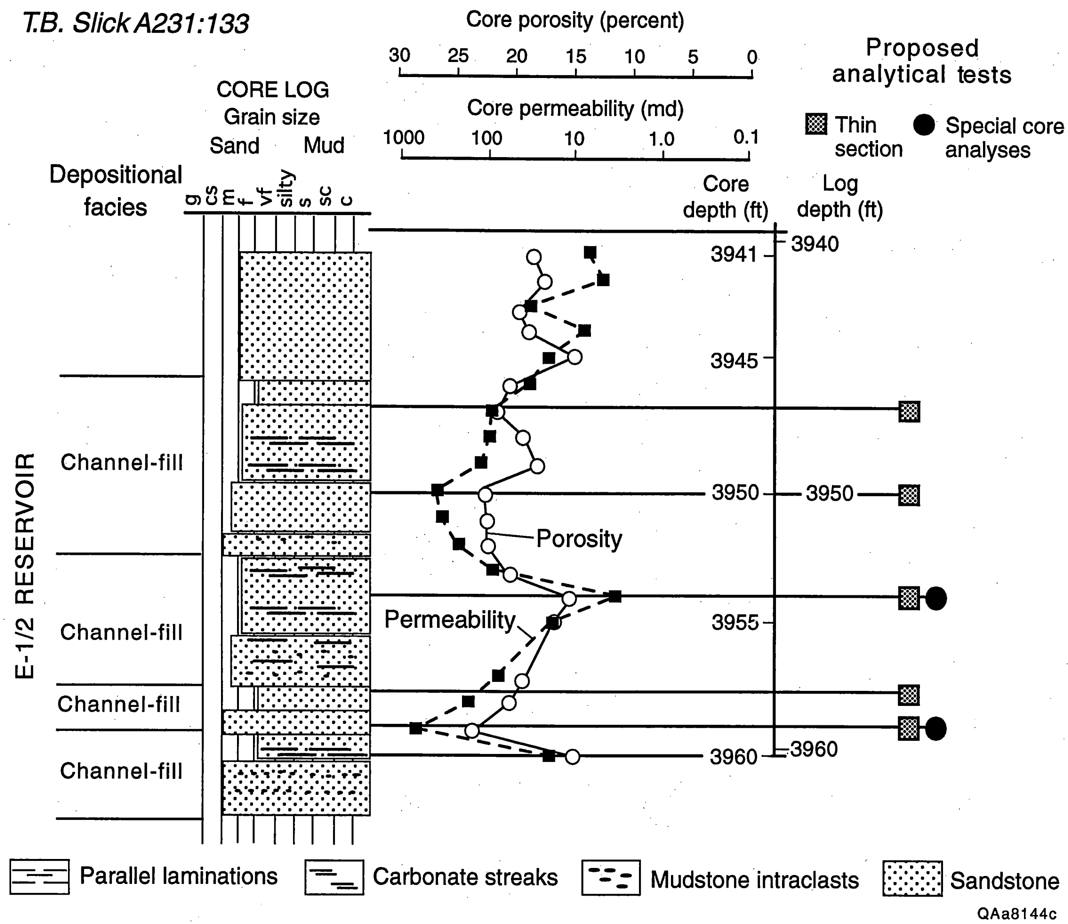


Figure 26. Graphic core log, T. B. Slick 231:133 well, Frio E reservoir zone, along with corresponding facies interpretations, core analysis data for porosity and permeability, and location of samples selected for petrographic and special core analyses.

Sandstones

Both channel-fill sandstones and crevasse splay sandstone facies were observed in core. Individual channel-fill sandstones range from 5 to 12 ft thick, and all exhibit upward-fining textures. Splay sandstones are less than 1 ft thick (e.g., 3,964 ft, 3,974 ft, 3,980 ft, Fig. 24) and appear more uniform or slightly upward coarsening in grain size. The thin (< 2 ft) nature of these splay facies suggests that crevasse development was localized and did not provide a significant contribution to sand deposition.

In addition to these primary facies distinctions, three channel subfacies, basal, middle, and upper channel-fill, could be identified on the basis of texture and sedimentary structures. The basal channel-fill facies refers to the lowermost portion of the channel-fill unit, is commonly coarser grained than the rest of the channel-fill (medium- to coarse- grained sand), and may include a gravel lag consisting of intraformational clasts of mudstone and calcareous nodules (e.g., 3,997 ft, 4,010 ft, Fig. 23, 3,875 ft, 3,894 ft, Fig. 25). The thickness of the basal facies of the channel-fill is typically less than 1 ft. The middle channel-fill facies comprises the majority of the channel-fill unit and has a grain size that normally ranges from medium to fine. Evidence of cross-stratification is very faint or not observable in core. The upper channel-fill facies consists of the top few feet of a channel-fill unit, is finer grained than the underlying middle channel-fill sandstone (fine to very fine 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. These profiles also illustrate the comparison of reservoir properties between channel-fill sandstones and splay sandstones and among the various channel subfacies. Channel-fill sandstones have lower permeability in the basal channel-fill, where there is commonly a well-developed mud chip zone (e.g., 3,997 ft, 4,009 ft, Fig. 24; 3,876 ft, 3,891 ft, Fig. 25). 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., 3,970 ft to 3,967 ft, 4,009 ft to 4,003 ft, Fig. 24; 3,876 ft to 3,870 ft, Fig. 25). Thin sandstones that are interpreted to represent crevasse splays or perhaps distal channel margins are generally finer grained than channel-fill facies and therefore possess lower porosity and permeability (e.g., 3,964 ft, 3,974 ft, Fig. 24).

Commonly two sandstone units are stacked together, and the presence of a mud chip zone at the base of the upper sandstone unit results in a significant reduction of permeability (e.g., 3,997 ft, Fig. 24; 3,875 ft, Fig. 25). 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., 3,989 ft, Fig. 24; 3,871 ft, Fig. 25).

Petrographic studies

Overview

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

Methods

The guiding approach to petrographic analyses was to conduct them within the context of the reservoir stratigraphic framework. Twenty-two representative samples from core in both wells were selected to provide good data coverage of each of the various reservoir facies and petrophysical rock types present within the Frio D and E reservoir zones in the two wells (Figs. 24, 25, and 26). Samples selected from the T. B. Slick 231/149 well were taken from the end trims of 1-inch-diameter core plugs so that petrographic parameters viewed in thin section could be directly compared to laboratory-derived porosity and permeability values. Several of these plugs were also selected for special core analyses. There are core analysis data for the T. B. Slick 231/133 core, but the original plugs from which these measurements were taken were not available. New core plugs were drilled from adjacent available core material for selected additional core measurements, and thin-section chips were taken from the ends of these new core plugs.

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

Texture

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

Framework Mineralogy

All Frio sandstones examined are mineralogically immature, and most samples are classified as feldspathic litharenites by the sandstone classification of Folk (1974) (Fig. 27a). The dominant framework constituents of most Frio Rincon samples are rock fragments, which on average compose one-half of all framework grains. The average composition of essential framework grains (normalized to 100 percent) from all 21 core samples is 17 percent quartz, 33 percent feldspar, and 50 percent rock fragments ($Q_{17}F_{33}R_{50}$). Compositions of samples from Rincon field generally coincide with compositions of other shallow (3,500 to 6,000 ft) Frio reservoir sandstones of the lower Texas Gulf Coast (Grigsby and Kerr, 1993). Deep (6,000 to 18,000 ft) Frio samples of the lower Texas Gulf Coast tend to be richer in quartz grains than the shallow Rincon samples, probably due to the greater degree of dissolution of feldspar and feldspar-rich rock fragments in the deep samples and resulting relative enrichment in quartz (Bebout and others, 1978; Loucks and others, 1986).

Most lithic fragments in the Frio Rincon samples are volcanic rock fragments (VRFs) (Fig. 27b), which compose an average of 59 percent of all rock fragments (range: 10 to 94 percent) and 18.7 percent of whole-rock volume (range: 6.5 to 26.0 percent). Coarser grained VRFs contain either plagioclase or predominantly orthoclase within a fine-grained groundmass and were derived from contemporaneous active volcanic areas in northern Mexico and West Texas (Loucks and others, 1986). Lindquist (1976) determined that most Frio VRFs from the Rio Grande Embayment are rhyolite and trachyte clasts, although we also observed numerous VRFs of basic composition, such as basalt clasts. In the outcrop equivalent to the Frio, sandstones contain VRFs of felsic and intermediate compositions as well as basalt grains (McBride and others, 1968). Rare VRFs in coarsest samples preserve original vesicular volcanic texture, with chert spherules now filling vesicles. Many isolated well-rounded chert and rare chalcedony grains within the Frio Rincon samples are probably vesicle-fills. Sedimentary rock fragments (SRFs), which constitute an average of 41 percent of all rock fragments in Frio Rincon samples (14.7 percent of whole-rock volume), include carbonate rock fragments (CRFs), chert, and rare shale, siltstone, and sandstone clasts. CRFs and chert predominate, with only minor to trace amounts (<2 percent of whole-rock volume) of the other lithic types. CRFs are micritic and are interpreted to have been derived from caliche (Lindquist, 1976). Frio Rincon samples also contain trace amounts of metamorphic rock fragments (MRFs), generally phyllite or slate.

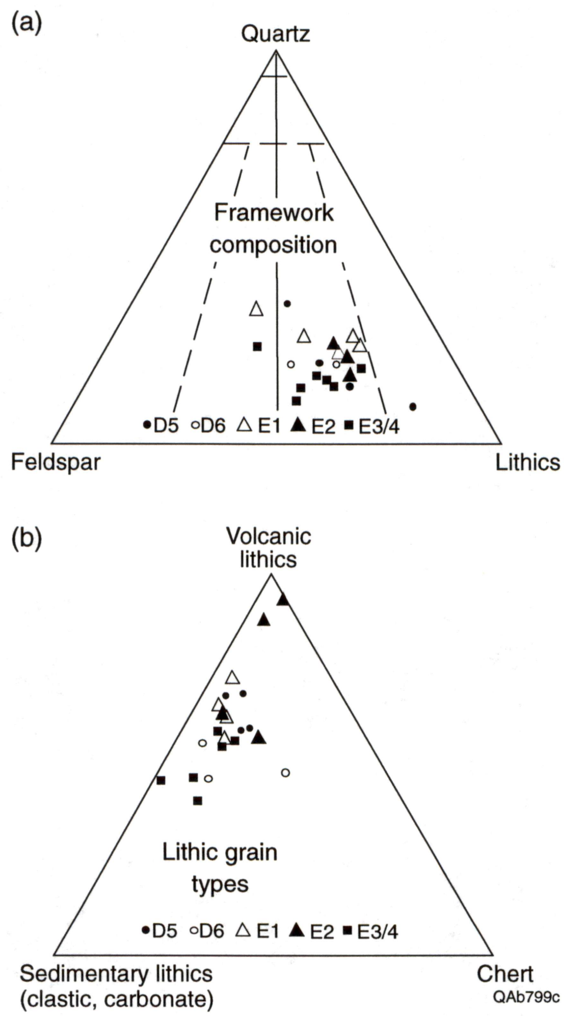


Figure 27. Ternary diagrams showing composition of Rincon D and E reservoir sandstones from thin-section petrography. (a) Percentages of quartz, feldspar, and lithic fragments. (b) Composition of lithic fragments, including volcanic rock fragments, sedimentary rock fragments, and chert.

Plagioclase is by far the most abundant feldspar in the samples, composing an average of 82 percent of all feldspars and 17.6 percent of whole-rock volume (range: 12.0 to 27.0 percent) (Table 3). Frio samples contain an average of 3.9 percent (whole-rock volume) orthoclase (range: 1.0 to 11.0 percent). Both plagioclase and orthoclase grains occur in several states of alteration (in order of abundance): fresh, vacuolized/sericitized, leached, and calcitized. Leaching of entire feldspar grains was a prominent stage in the diagenetic evolution of the Frio Rincon reservoirs, and partially and wholly leached grains contribute to reservoir porosity and permeability. Both topics are discussed more fully in subsequent sections.

Quartz grains are third in relative abundance of all framework grains (average of 10.6 percent of whole-rock volume; range: 4.5 to 16.5 percent) (Table 5). Most quartz grains are single crystals. Rare grains in each sample, however, are polycrystalline, indicating, along with the sparse MRFs, a minor metamorphic source terrane for Frio Rincon samples.

Accessory minerals in Frio Rincon samples include, on average, only trace amounts of muscovite and biotite, and nearly 1 average whole-rock percent of patchy organic material (Table 5). Pyrite is only locally finely disseminated in matrix and organics.

Detrital Clay Matrix

Frio Rincon reservoir rocks are low in clay matrix content, and it is not a significant factor in controlling reservoir quality. Samples contain an average whole-rock volume of 2.2 percent clay matrix (range: 0 to 9.0 percent) (Table 5). Illite and/or illite/smectite are the dominant clay minerals. One Frio Rincon sample (3964.1 ft) is notable in its abundance of detrital illite and/or illite/smectite matrix. This sample contains 48.5 whole-rock percent matrix, which is interpreted to be the alteration product of volcanic ash in a bentonite bed. Because this bed does not represent reservoir rock, its matrix content was not included in computations of the average content of the reservoir facies. Volume of pore-filling matrix (detrital clay) and clay cements is consistently low in the samples and is not considered to be a significant influence on reservoir quality.

Table 5. Summary of petrographic data for Rincon sandstones.

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

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

Cements

Authigenic cements collectively constitute a range of 4.0 to 32.5 percent of the whole-rock volume in the Frio Rincon samples, with a mean value of 11.6 percent (Table 5). Authigenic cements include (in order of abundance) non-ferroan calcite, chlorite, and kaolinite. There are also trace amounts of quartz and feldspar overgrowths and illite/smectite grain-rimming cement. Calcite dominates other cements, with an average of 11.2 percent, close to the average sample content of all cements. Chlorite and kaolinite constitute an average of 0.4 and 0.1 percent of all cements, respectively.

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

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

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

Porosity

Total porosity observed in thin section varies from 2.5 to 29.5 percent of whole-rock volume, with an average value of 17.3 percent. Secondary porosity composes most of visible thin-section porosity in the Frio Rincon samples. It varies considerably from 2.5 percent of whole-rock volume in heavily calcite-cemented samples to 28.0 percent in heavily leached samples (average: 15.7 percent). Secondary porosity is developed as voids within partially dissolved framework grains (mainly feldspars and VRFs) and as oversized pores that once contained framework grains and/or calcite cement. Little primary porosity (average: 1.5 percent) is preserved in the samples. It exists as small intergranular voids at least partially lined with chlorite or calcite crystals growing into the voids within areas of closely spaced framework grains. However, in most cases it is difficult to identify primary porosity because such textural relations are not present. The Rincon samples underwent at least two stages of dissolution of framework constituents and calcite, the dominant pore-filling cement (Fig. 28). Therefore, textural relations typically cannot be used to confidently establish whether observed porosity is original.

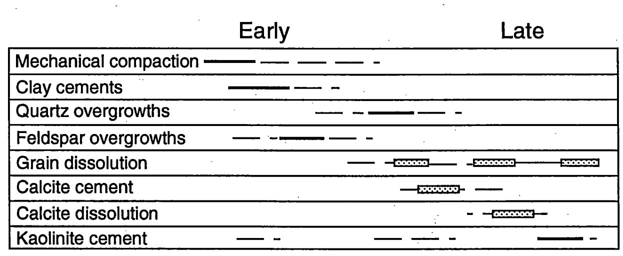


Figure 28. Diagenetic sequence diagram, Rincon D and E reservoir sandstones.

Diagenetic Sequence

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

The diagenetic sequence of mineralization of the Frio Rincon samples was deduced from textural relations among the framework grains and cements observed in thin section. Where quartz and feldspar overgrowths are present, chlorite and illite/smectite grain-rimming cements lie, at least partially, between the grain and the overgrowth, thus indicating that overgrowth formation postdated clay cementation. Feldspar overgrowths probably predate, or are in part contemporaneous with, quartz overgrowths in these shallow Frio samples, although direct textural evidence is lacking. However, other studies of Frio diagenesis inferred these same temporal relations (Lindquist, 1977; Bebout and others, 1978; Loucks and others, 1986). Dissolution of the least chemically stable framework grains and rock fragments (feldspars, VRFs) began with deeper burial and continued throughout the burial history of the Rincon reservoirs. There were probably discontinuous periods of enhanced dissolution (Fig. 28), perhaps coinciding with episodes of migrating pore fluids. Loss of detrital grains from sandstones represents one of the volumetrically most important diagenetic processes that has occurred and is occurring in the Frio Formation (Milliken, 1989). In the few heavily calcite-cemented samples examined, calcite cement fills voids that are one to several grain diameters in size and are a replacive component of partially leached framework grains, all evidence that calcite cementation followed significant grain dissolution in the Rincon reservoirs. However, most Rincon samples exhibit abundant porosity due to subsequent dissolution of most of the calcite cement, as indicated by characteristic residual patches of sparry cement with corroded edges. Where calcite-cement volume is low due to dissolution and creation of porosity, sample porosity is higher.

Calcite dissolution was a significant diagenetic stage that was magnified by the preceding and contemporaneous leaching of framework grains, particularly feldspars and VRFs. Sparse patchy kaolinite cement fills voids created by the loss of calcite cement. However, earlier kaolinite cementation is also inferred.

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

Determination of Finest Scale Genetic Units

Correlation of Bounding Surfaces and Reservoir Genetic Units

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

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

Sandstone Geometry and Depositional History

Frio E Reservoir Units

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

The Frio E reservoir zone includes strata from the F shale marker to the E shale marker (Fig. 29). The entire zone is composed of four, predominantly upward-fining units divided by three low-resistivity marker beds. Each unit between two shale markers represents a depositional parasequence that together makes up a larger-scale, back-stepping, or retrogradational cycle that took place during deposition of the entire E zone.

The onset of sand deposition in the Frio E stratigraphic interval is represented by the E-4 unit (Fig. 30). 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. The channels are distinctly separated by floodplain facies in the downdip portion of the map area, but in the updip portion, the channels appear to be better connected, suggesting some flow-communication would be present between the two. Higher up section in the E-2 unit, dip-oriented NW to SE channel geometries still predominate. In the updip portions of these channels, some minor strike-oriented features are apparent, and maximum sand thicknesses have stacked up in a more updip position relative to earlier deposition, indicating a backstepping pattern caused perhaps by relative sea-level rise.

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

Depositional History of Frio D Reservoir Units

The productive D reservoir interval also consists of four discrete depositional parasequences divided by three low-resistivity shales (Fig. 29). These are identified as the D-3, D-4, D-5, and D-6 units, and together they form a larger-scale depositional sequence that includes both progradational and aggradational units. Located above the E flooding surface, the D-6 unit is the lowermost sandstone of the D reservoir zone, and follows a relatively extended period of predominantly mud deposition. The strike-elongate sandstone pattern in the D-6 unit is believed to reflect initial progradation and development of a thin delta front. Upward-coarsening and blocky log responses in many of the electric log profiles of D-6 units are further evidence that delta-front sand facies make up this strike-oriented sand body. Dip-elongate channel deposition appears to be present in the northern portion of the study area, as well as across the center of the map where the strike elongate delta front sandstone is dissected by narrow upward-fining channel facies.

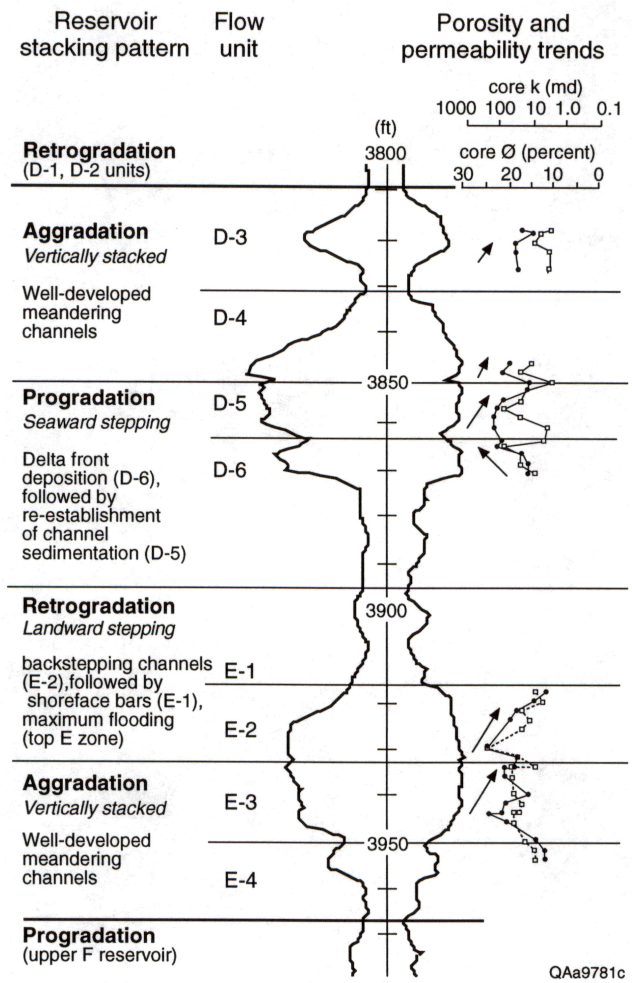


Figure 29. Representative SP/resistivity log illustrating succession of stacking patterns developed within the Frio E and D reservoir units. Conventional core analysis data posted on the right illustrate porosity and permeability trends commonly observed in each subunit that generally correspond to SP and resistivity bell and funnel curve shapes indicative of upward-fining channel sandstones and upward-coarsening bar sandstones, respectively.

Progradation continues during deposition of the D-5 unit. The overall sandstone geometry in the D-5 consists of northwest-southeast trending, dip-parallel channel facies (Fig. 30). Because of the greater thicknesses of mapped sand patterns, it is difficult to distinguish boundaries between individual channels. The thickest development of sandstone is present as a relatively narrow channel feature that runs from northwest to southeast across the study area. The D-5 zone also has evidence of some reworked strike-oriented delta-front remnants, and log correlation in some areas indicates that this unit may be mapped as two discrete episodes of channel deposition. The uppermost Frio D reservoir subunits represent a return to more discrete channels and aggradational sedimentation. Both the D-4 and D-3 units are dominated by dip-elongate fluvial-channel deposition. Sediment load being carried by these channels appears to be reduced from earlier D-5 deposition, as evidenced by thinner development of sandstone and more clearly identified channel margins. The two channel systems mapped in the D-4 unit appear to be in communication in the updip portion of the map area. The D-3 unit consists of a single, relatively broad channel system. In addition to the blocky and upward-fining log patterns that characterize channel-fill facies, serrate and thin upward-coarsening responses diagnostic of levee and crevasse splay facies are also observed adjacent to channel margins in these two units.

Establish Fluid-Flow Trends in the Reservoir

Initial Fluid Properties

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

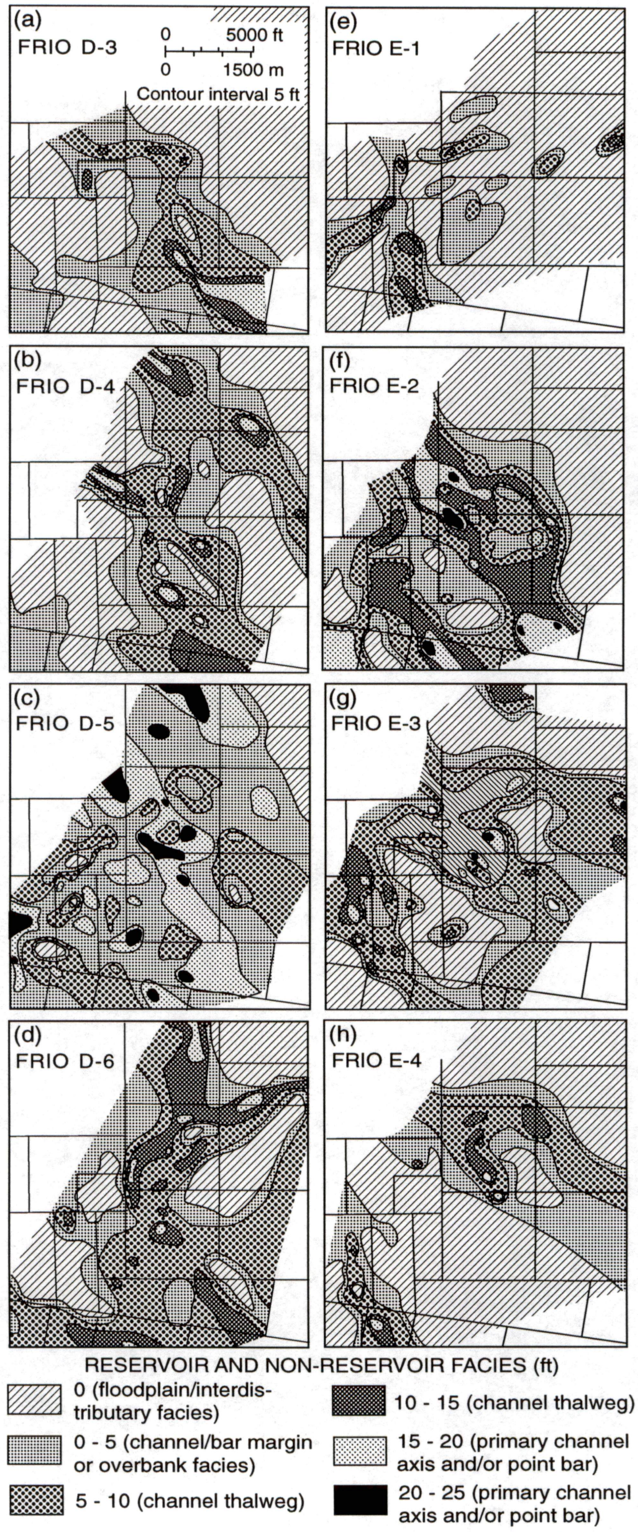


Figure 30. Series of net sandstone isopach and facies maps showing changes in the distribution of facies and sandstone facies geometry for the Frio E-4, E-3, E-2, and E-1 reservoir units and Frio D-6, D-5, D-4, and D-3 reservoir units.

Field Production History

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

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

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

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

Evaluation of Areal Trends of Past Oil Production

Areal patterns of reservoir development identified by isoproduction contours reveal the general distribution of hydrocarbon storage capacity and degree of flow communication within a productive reservoir zone. These maps also may indicate areas where there are significant production contrasts that may be a direct result of flow barriers created by stratigraphic heterogeneity. Most well completions in a given reservoir include a stratigraphic interval that spans more than one flow unit, and as a result, cumulative production data on a per-well basis do not often provide 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 structure, 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, structural maps (Fig. 31 a,b) and cumulative production isopach maps (Fig. 31c,d) 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 (Fig. 31e,f). The cumulative production map for the E reservoir shown in Figure 31c illustrates the trend of high production following along the lower edge of the structure. The correspondence between better production and the downdip edge of the reservoir is due to efficient water drive in the lower portions of the reservoir. In addition to structural position, another control on

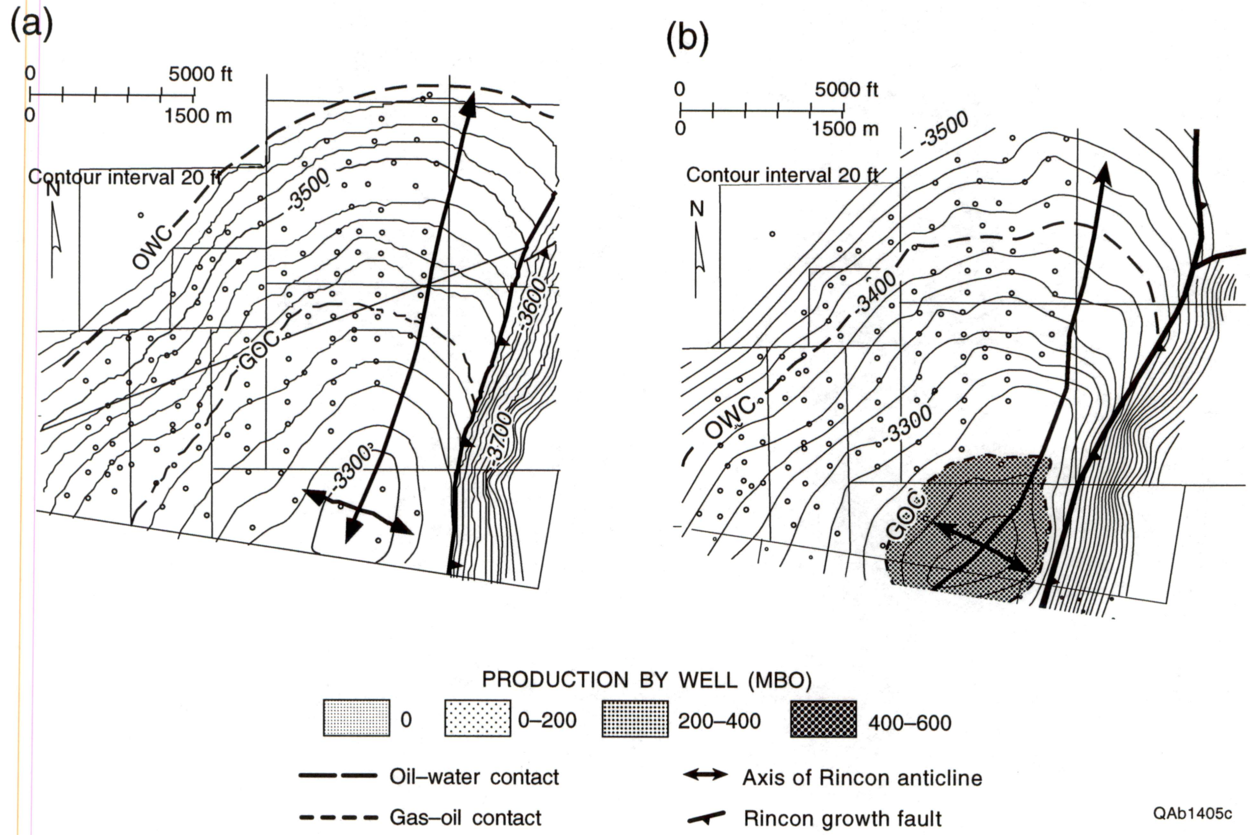


Figure 31. Comparison maps illustrating differences in overall reservoir geometry and distribution of production, Frio D and E reservoir zones. Maps on the left for the Frio E reservoir show (a) representative structure contoured on the top of the Frio E unit, showing the anticlinal pattern of the Rincon structure and location of the down-to-the-east Rincon growth fault; and (c) cumulative oil production for the combined Frio E reservoir; and (e) isopach map from the total E sandstone reservoir zone, showing distribution of net sandstone thickness and depositional geometry. The stacking of greater sandstone thicknesses in the updip portion of map area may have created increased flow communication between adjacent channels along the crest of the structure and caused the relatively high recovery efficiency of the E reservoir. Maps illustrating structure (b), distribution of cumulative oil production (d), and total net sandstone thickness (f) are presented on the right for the Frio D reservoir. In contrast to the Frio E zone, the strong dip-elongate depositional pattern and narrower geometry of Frio D channels make this reservoir appear more compartmentalized and may explain lower overall recovery efficiency.

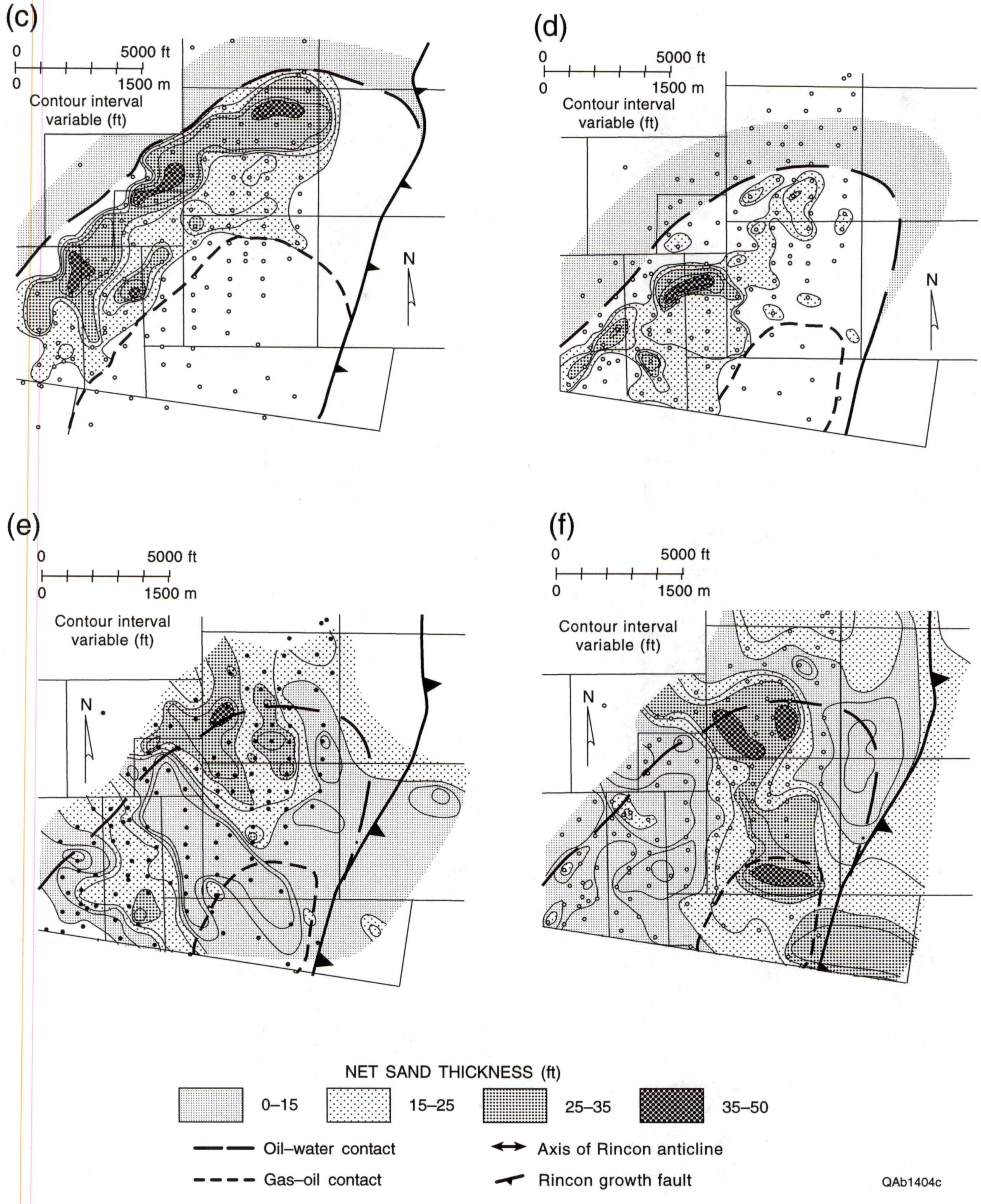


Figure 31. (cont.)

cumulative production appears to be differences in net thickness. The composite E reservoir net sandstone isopach map shows greatest sand thicknesses occurring in the updip portion of channels, and comparison with the production map indicates that higher production roughly corresponds to areas of thicker net sandstone that generally follow along channel depositional axes (Fig. 31e).

Maps comparing the distribution of oil production in the D zone with structure show a similar pattern as was observed in the E reservoir zone, with production "hot spots" oriented along strike parallel to the crest of the anticlinal structure (Fig. 31d). Areas of high production within the D reservoir appear to be much more isolated than was observed on the E cumulative production map (Fig. 31f). The total net sandstone thickness map for the combined D interval shown in Figure 31e illustrates the strongly dip-oriented pattern of the composite D sandstone interval. 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 individual reservoir subunit should reveal causes of stratigraphic heterogeneity that have resulted in compartmentalization of oil volumes. The results should lead us to a better understanding of how reservoir architecture may be controlling recovery efficiency and identify areas with high potential for containing undeveloped resources that may be targeted for incremental recovery.

Integrating Fluid-Flow Trends in the Reservoir

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

Effect of Sandstone Geometry on Oil Production

The Frio D and E reservoir intervals illustrate a systematic evolution of sediment transport styles and stratigraphic stacking patterns (Fig. 29). These are: (1) aggradation in the lower Frio E-4 and E-3 reservoir units, (2) retrogradation in the upper Frio E-2 and E-1 units,

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

Matching Stratigraphy with Reservoir Production

Reservoir Development Patterns within the Frio E Reservoir

Reservoir development within each unit was indicated by identifying wells with completions within the stratigraphic interval that comprises each unit. In addition, wells were identified that were not perforated within the mapped zone but were completed in a reservoir subunit stratigraphically above or below the mapped unit that may have been in partial or complete vertical communication. The series of reservoir geometry/development maps prepared for the E reservoir units are shown in Figures 32 through 35.

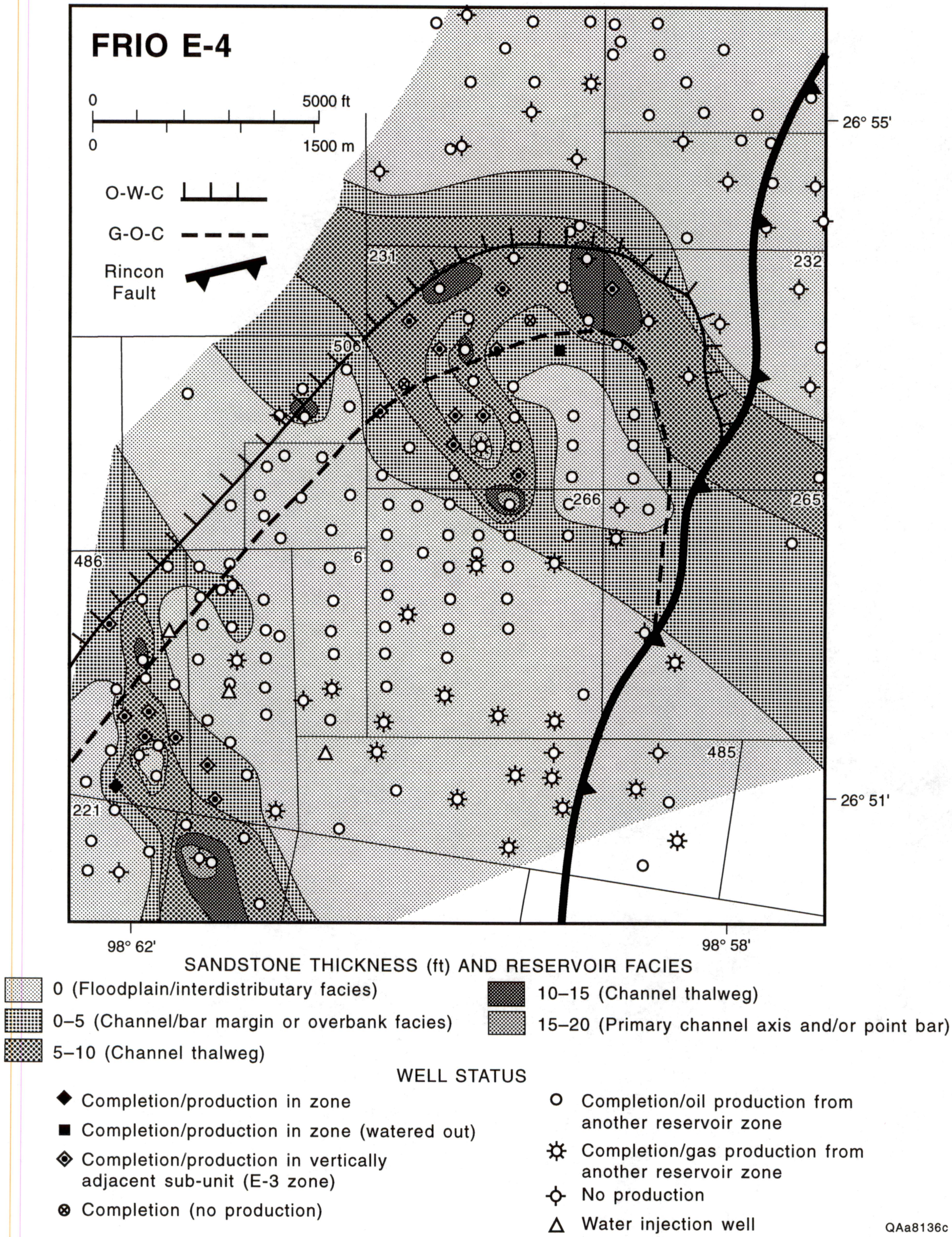


Figure 32. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio E-4 reservoir unit.

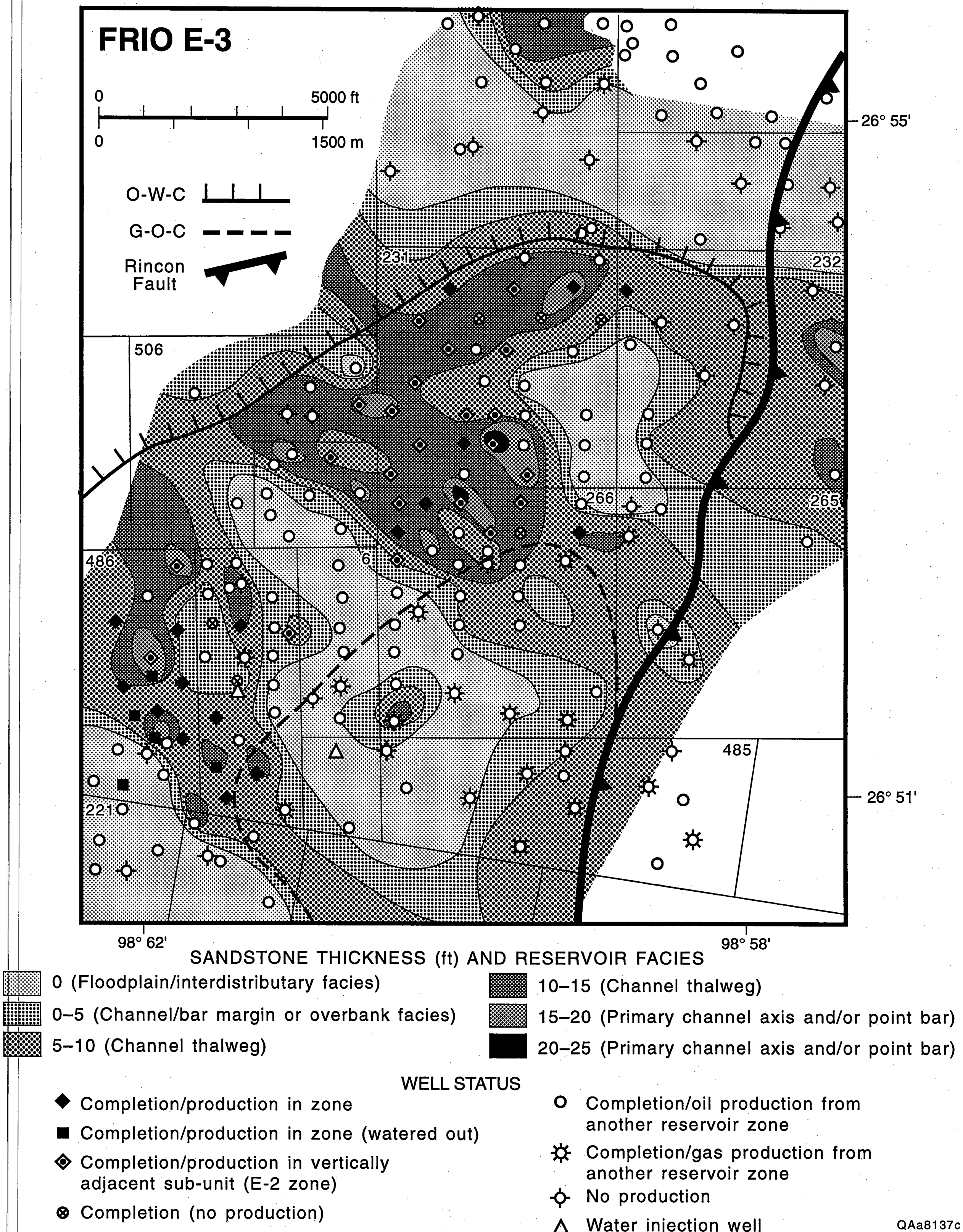


Figure 33. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio E-3 reservoir unit.

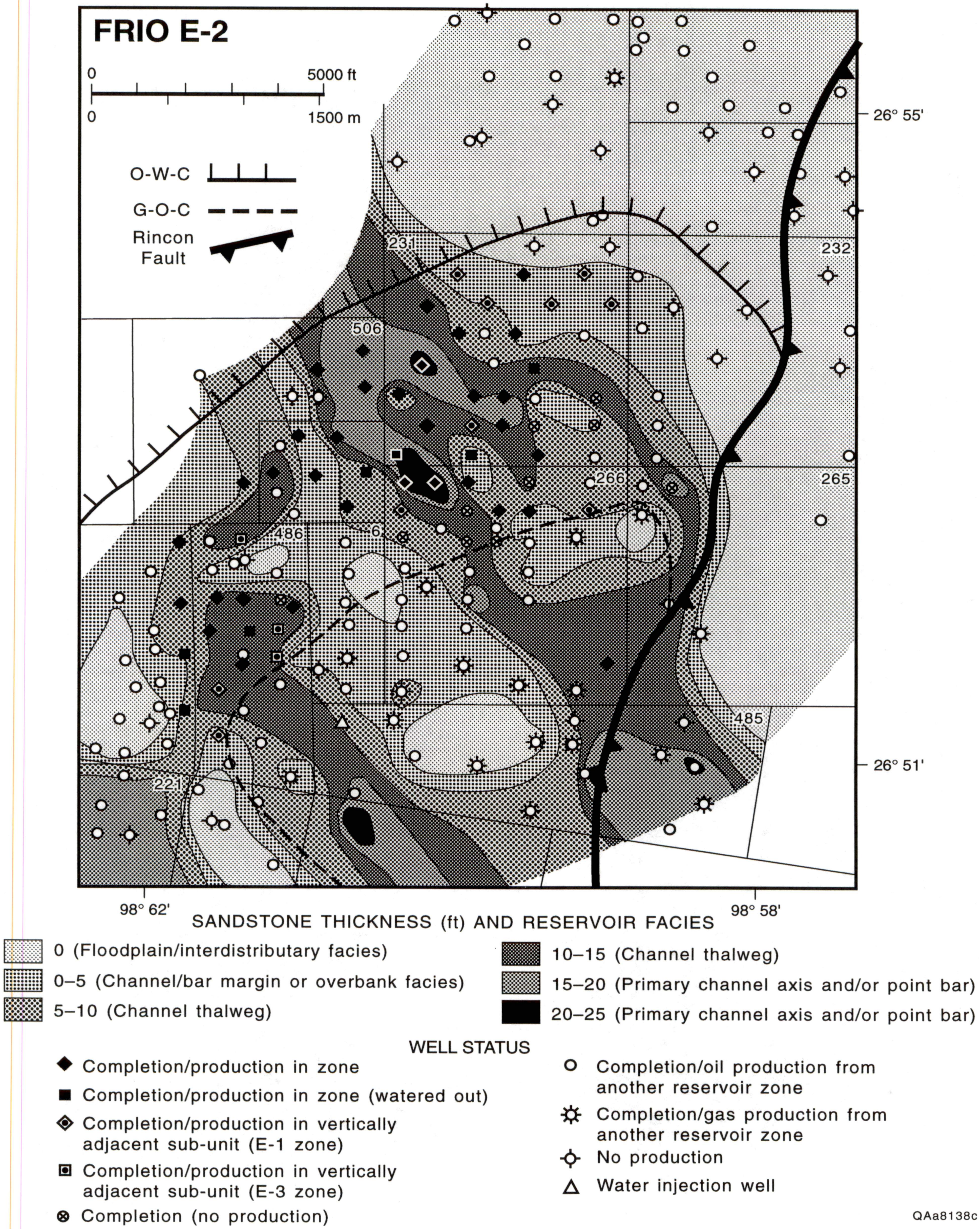


Figure 34. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio E-2 reservoir unit.

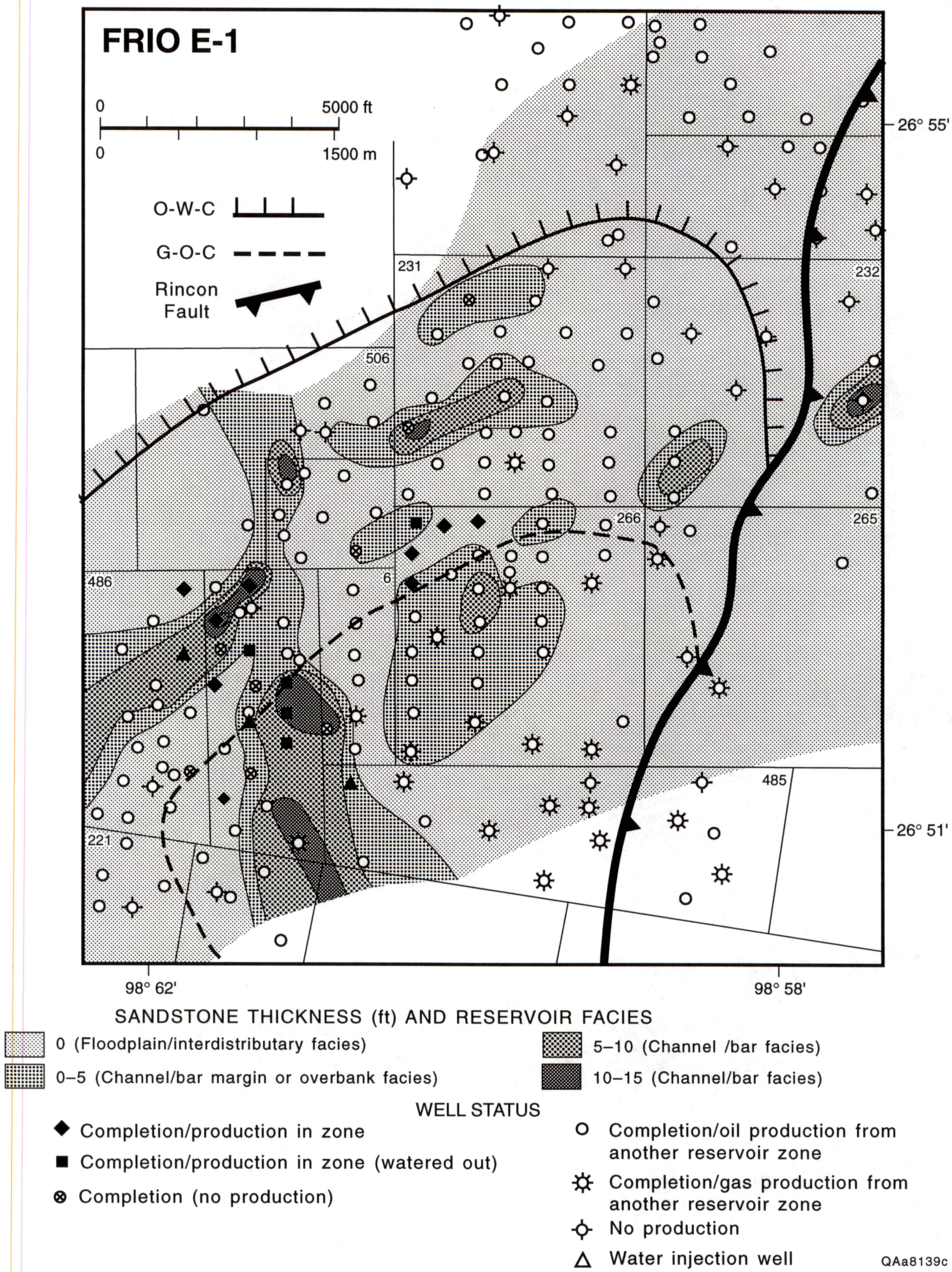


Figure 35. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio E-1 reservoir unit.

The Frio E-4 unit has the least number of completions of the three E reservoir units (E-4, E-3, and E-2) that are characterized predominantly by channel sedimentation. This unit consists of two discrete dip-oriented channel bodies that are separated laterally by at least 3,000 ft of non-reservoir floodplain facies (Fig. 32). 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 & E-4 reservoir zone.

E-3 unit reservoirs appear to consist of three separate channel systems oriented northwest to southeast across the field study area (Fig. 33). 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 subjacent zone, primarily the overlying E-2 reservoir, and have produced oil, some of which may be properly allocated to the E-3 unit. More than 3 MMBO of production has currently been assigned to E-3 reservoir.

The Frio E-2 reservoir unit possesses the greatest number of completions (64) and producing wells (46) of all the E reservoir subunits. The mapped sandstone geometry (Fig. 34) 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 (1250 md+) measured in the field. 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 E-1 and E-2 sandstones were developed as though they were usually in flow communication, and extensive development in the E-2 reservoir has likely produced much of the E-1 oil. Sandstone isopach mapping and evaluation of log facies in this study suggest that the E-1 sandstone was deposited in a retrogradational cycle where pre-existing channel units have been eroded and reworked into a series of strike-elongate bar sands that cover most of the mapped study area (Fig. 35). 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.

Reservoir Development Patterns within the Frio D Reservoir

Composite maps illustrating the distribution of reservoir sandstone, facies patterns, and level of development for each of the D reservoir subunits are presented in Figures 36 through 39. As discussed previously, the lowermost D reservoir unit, the D-6 sand, has been interpreted to represent part of a progradational cycle of sedimentation during which strike-elongate sandstone bars deposited during the previous retrogradational cycle are being eroded and transected by a dip-oriented channel system that trends across the center of the map area (Fig. 36). Upward-coarsening profiles observed on electric logs indicate the presence and northeast-to-southwest distribution of the bar sandstone facies that appears to be in the process of being dissected by the northwest-to-southeast oriented channel. The D-6 unit has relatively few completions (14), and although some of these completions were productive, all production was originally assigned to the composite D-5 reservoir zone.

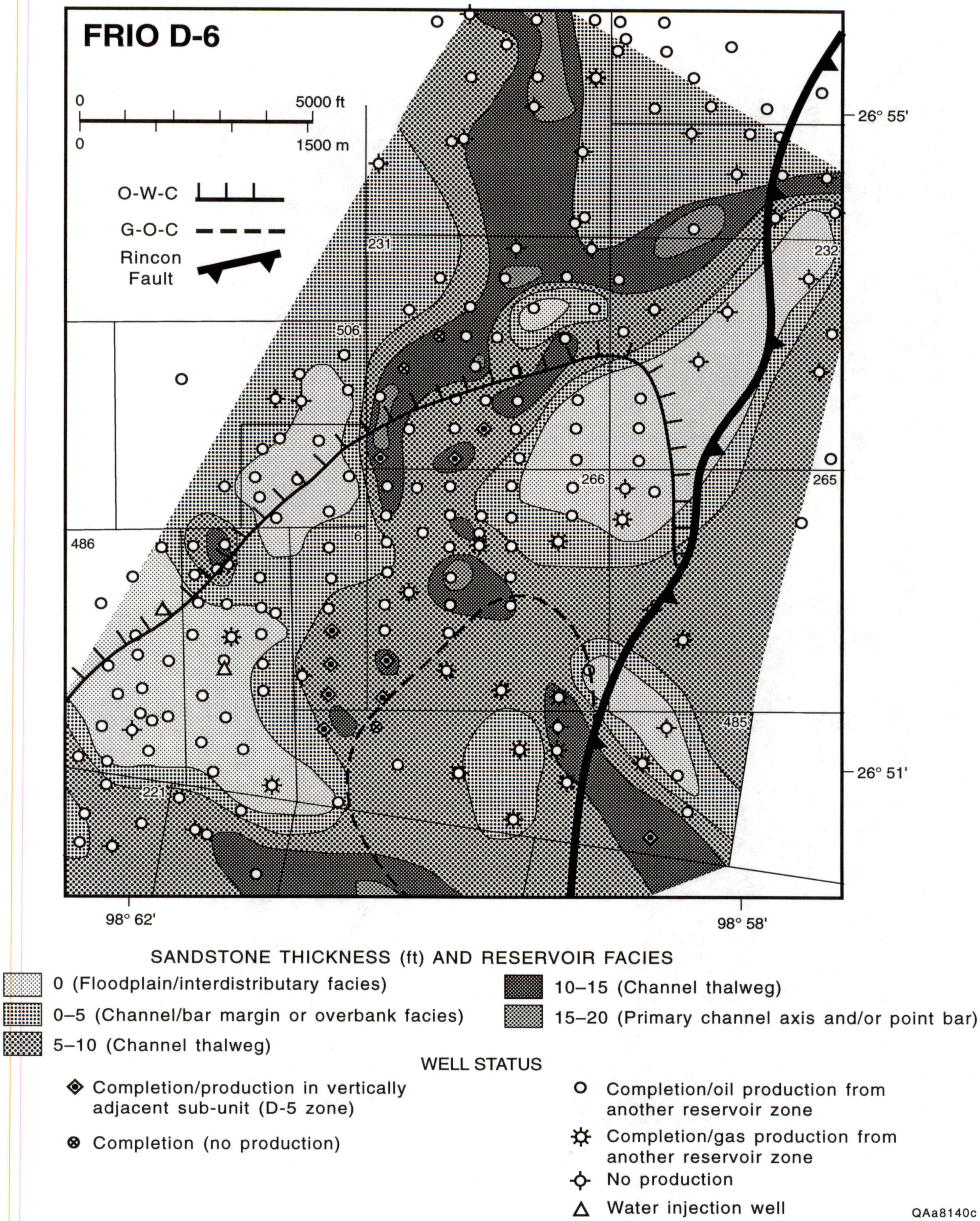


Figure 36. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio D-6 reservoir unit.

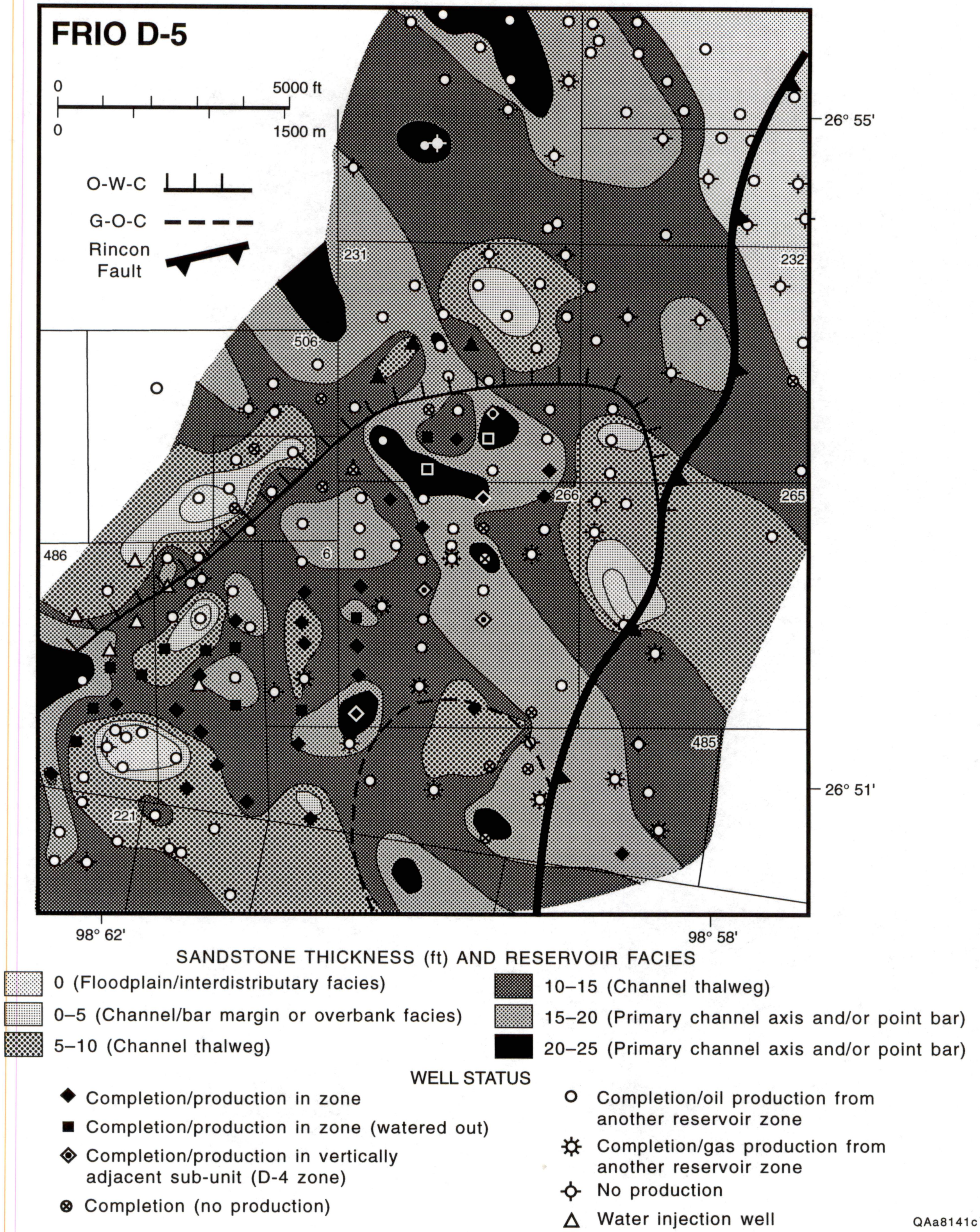


Figure 37. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio D-5 reservoir unit.

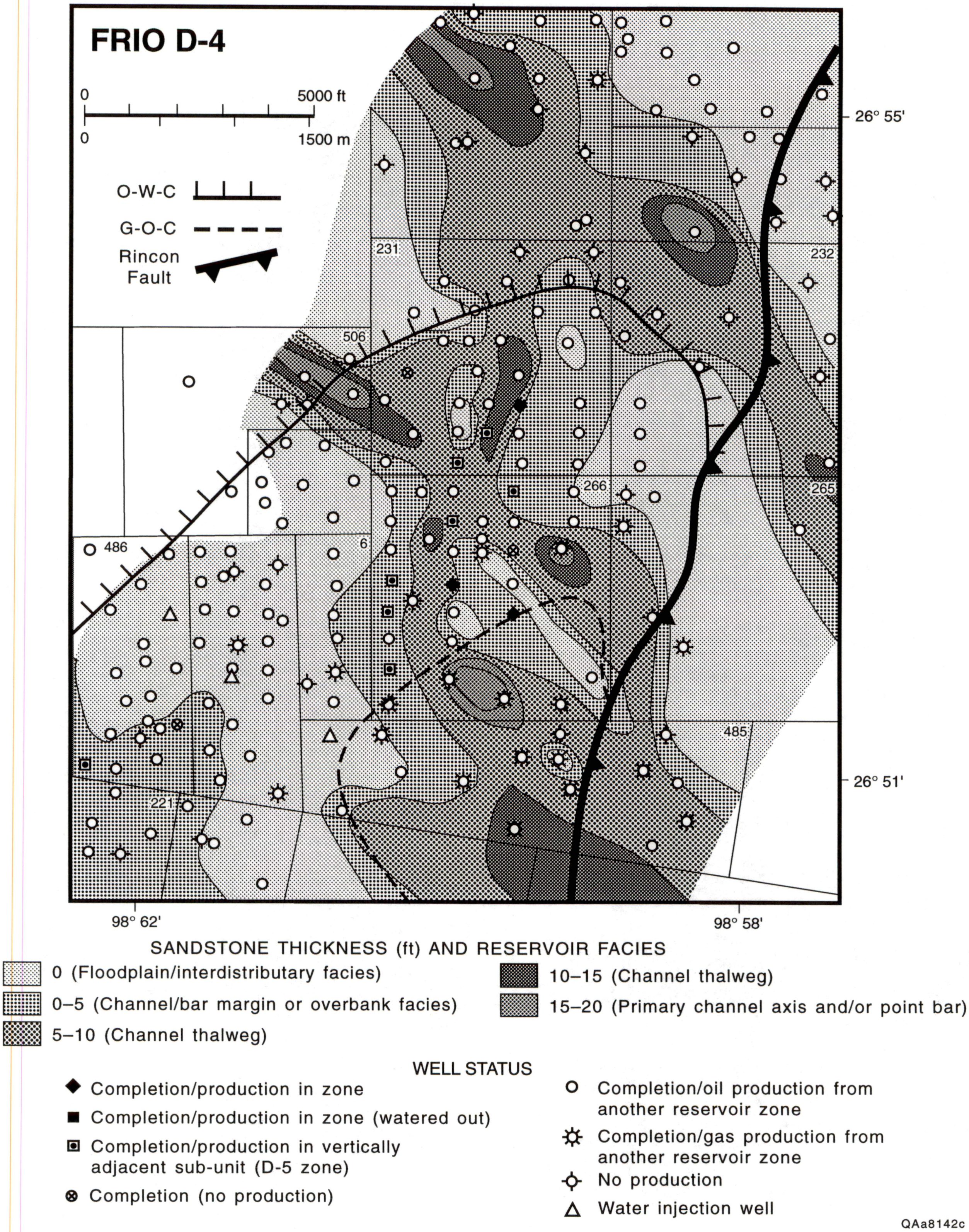


Figure 38. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio D-4 reservoir unit.

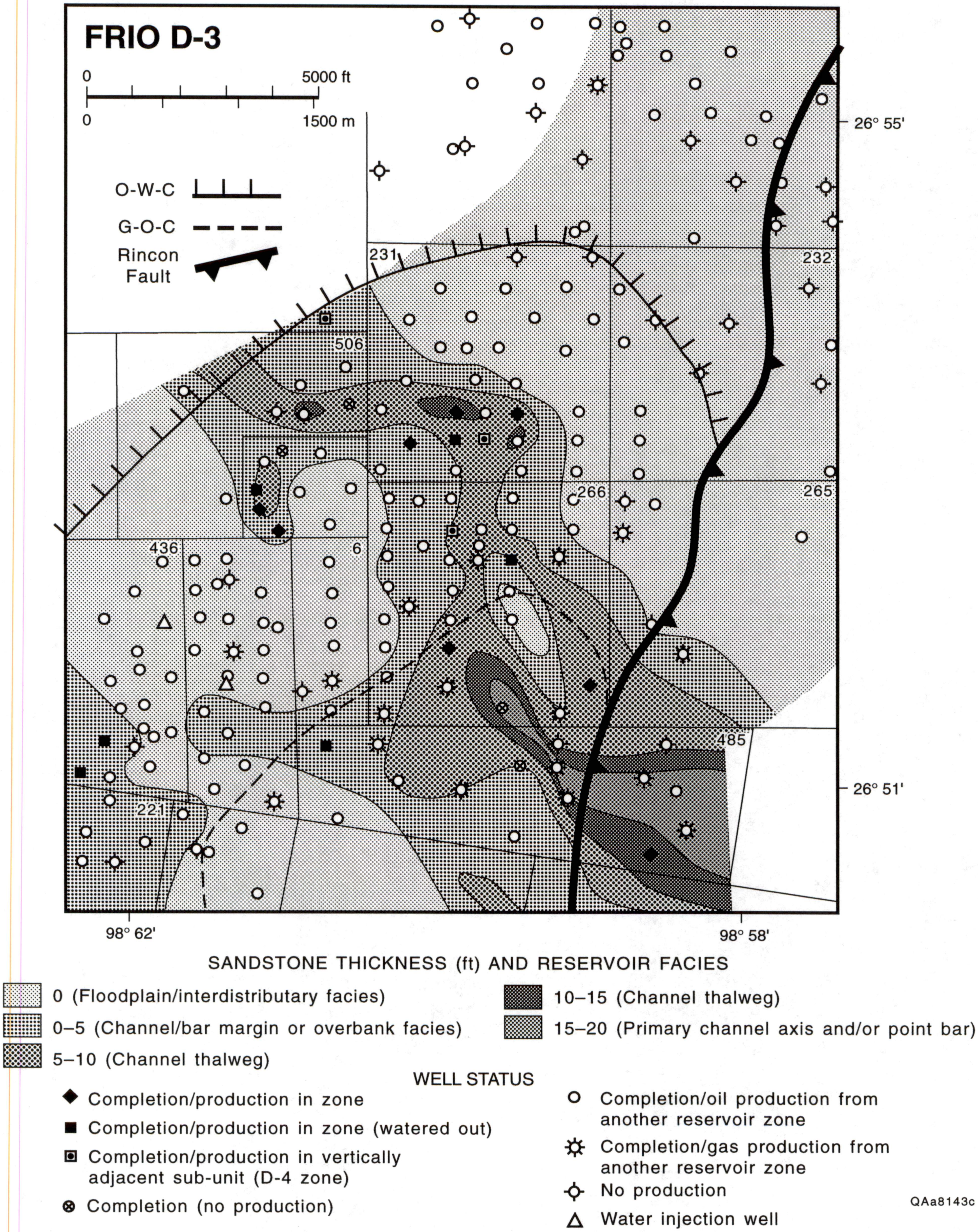


Figure 39. Map illustrating sandstone thickness distribution, corresponding reservoir facies geometry, productive limits, and level of development, Frio D-3 reservoir unit.

As illustrated in Figure 37, the depositional geometry of the Frio D-5 subunit is very complex. The isopach map pattern reveals the presence of a primary axis of deposition, indicated by the thickest development of sandstone, running from northwest to southeast across the center of the map area. The relatively thick sandstone throughout this reservoir zone obscures much of the depositional pattern. The D-5 zone has more completions (60) and productive wells (39) than all other D reservoir units combined, and production reported for the composite D-4, 5, 6 reservoir zone totals in excess of 6 MMBO. Assessment of the permeability distribution within the D-5 unit suggests that there are several areas where 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 (Fig. 38). 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 with 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 (Fig. 39). 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.

Reservoir Petrophysical Model Development

Porosity and Permeability Modeling

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

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

Porosity and Permeability Distribution for Primary Facies Types

Measured porosity and permeability values from wireline cores were analyzed with their sample depths and corresponding reservoir subunit and facies types identified from patterns on sandstone isopach maps and electric log signatures, respectively. Evaluation of log facies and sandstone distribution for each of the reservoir subunits reveals three primary depositional facies types: (1) channel (dip-elongate) sandstone reservoir units, (2) bar (strike-oriented) sandstone reservoir units, and (3) overbank (levee and crevasse splay) units. Basic descriptive statistics, including histograms and linear regressions of porosity vs. permeability, were calculated for each different subgroup of data. Frequency distributions of core porosity and permeability values grouped according to the three general facies types are illustrated in Figure 40. Channel units, on average, possess higher values of porosity and permeability (21% mean f, 61 md mean k) than the bar sandstone units (mean ϕ of 18%, mean k of 24 md). Overbank facies have lower porosities (mean 18%) and substantially lower permeabilities (mean 12 md) than either channel or bar sandstones. Mean permeability values for thin upward-coarsening log patterns interpreted to be crevasse-splays are 25 md (range 0.3–199 md) and are 5 md (range 0.1–54 md) in units with serrate log responses classified as levee facies. These poorer quality overbank facies generally are not significant reservoirs.

The porosity-permeability relationship between facies is distinctly different. Porosity and permeability for bar sandstone facies in the E-1 and D-6 reservoir sub-units and for all fluvial facies types in the other reservoir units were crossplotted, and a nonlinear regression was performed for each group. The resulting equations for the regression lines demonstrate the different porosity-permeability relationships between these facies types. Similar porosity values have the lowest corresponding permeability for overbank facies, midrange for channel sandstone facies, and the highest for bar sandstone facies (Fig. 41). Therefore, greater accuracy in permeability estimation can be achieved by calculating permeability on a facies-by-facies scale.

Well Log Analysis

Petrophysical analysis of the Frio D and E reservoirs in Rincon field includes (1) integrating core data with geophysical log data, (2) quantifying petrophysical properties from wireline logs, and (3) testing the validity of these derived properties by comparing maps of log facies and net

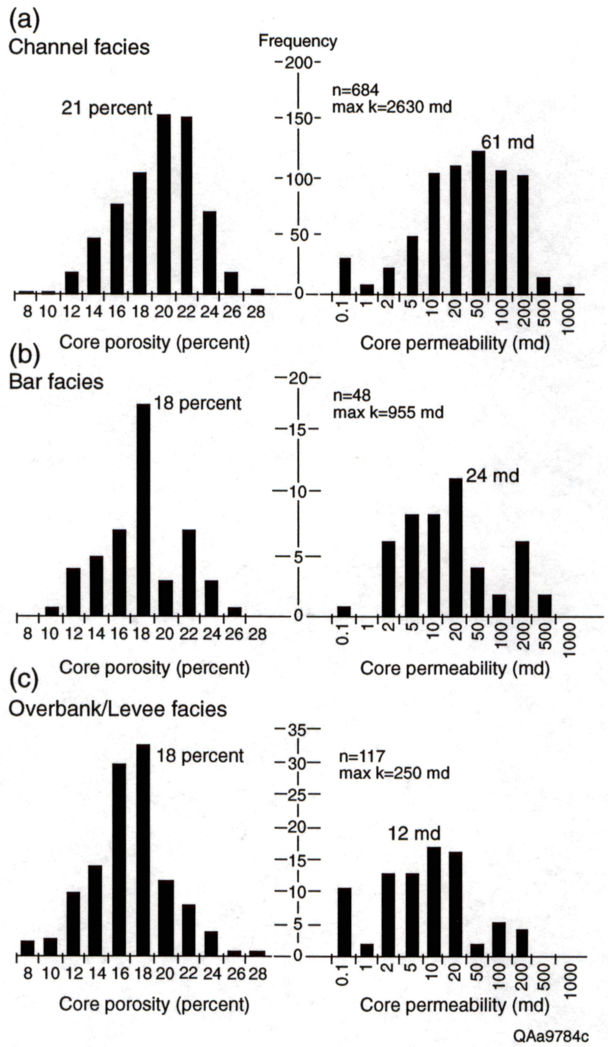


Figure 40. Histograms illustrating the distribution of porosity and permeability values according to each of the mapped reservoir facies: (a) aggradational channels, (b) retrogradational bars, and (c) overbank (splay and levee) facies.

sandstone thickness with reservoir-volumetrics maps. The development of petrophysical models to calculate porosity, permeability, and water saturation from geophysical log data is based on thorough evaluation of wireline core analysis data, results from special core analyses, petrographic identification of the type and distribution of clay minerals, and calculated shale volumes of reservoir units. The lack of porosity log data in the field (only six wells have porosity logs) requires our petrophysical characterization of porosity to be based primarily on indirect methods using non-porosity logs such as SP and resistivity.

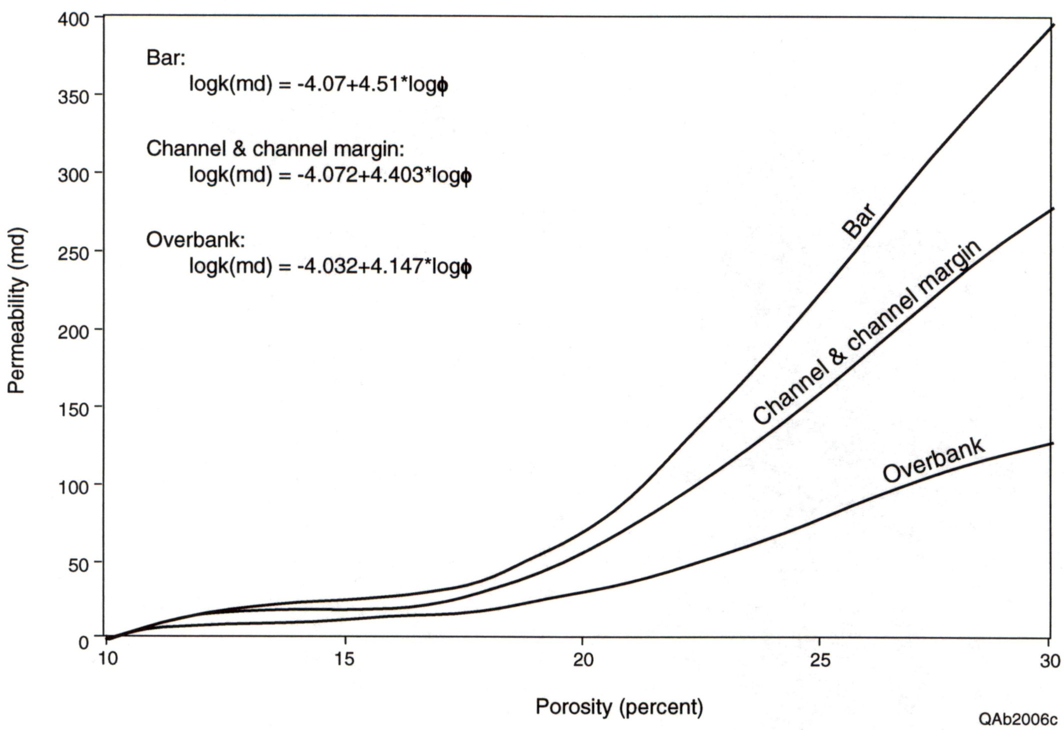


Figure 41. Nonlinear regression analysis on a facies-by-facies scale results in an equation to predict permeability from porosity.

An example of core and porosity log data over the E reservoir in the T. B. Slick A149 well is shown in Figure 42. This is one of two wells for which we have whole core, abundant conventional core analyses, and a modern log suite including gamma ray, deep induction, density, and compensated neutron log curves. There is no spontaneous potential log for this well, and this is most unfortunate, because virtually all of the other wells in the field have SP logs (and no gamma ray), and therefore no whole core-SP log calibration can be made. Comparisons of the resistivity curve (1) with the core graphic log (2) and with porosity (3) and permeability (4) data measured on core samples show a reasonable correlation between resistivity, core facies, and porosity and permeability. Sandstones with reduced porosity and permeability correspond to locations described in core as basal channel facies, or they are carbonate cemented. These permeability variations are not readily recognizable from the log data alone.

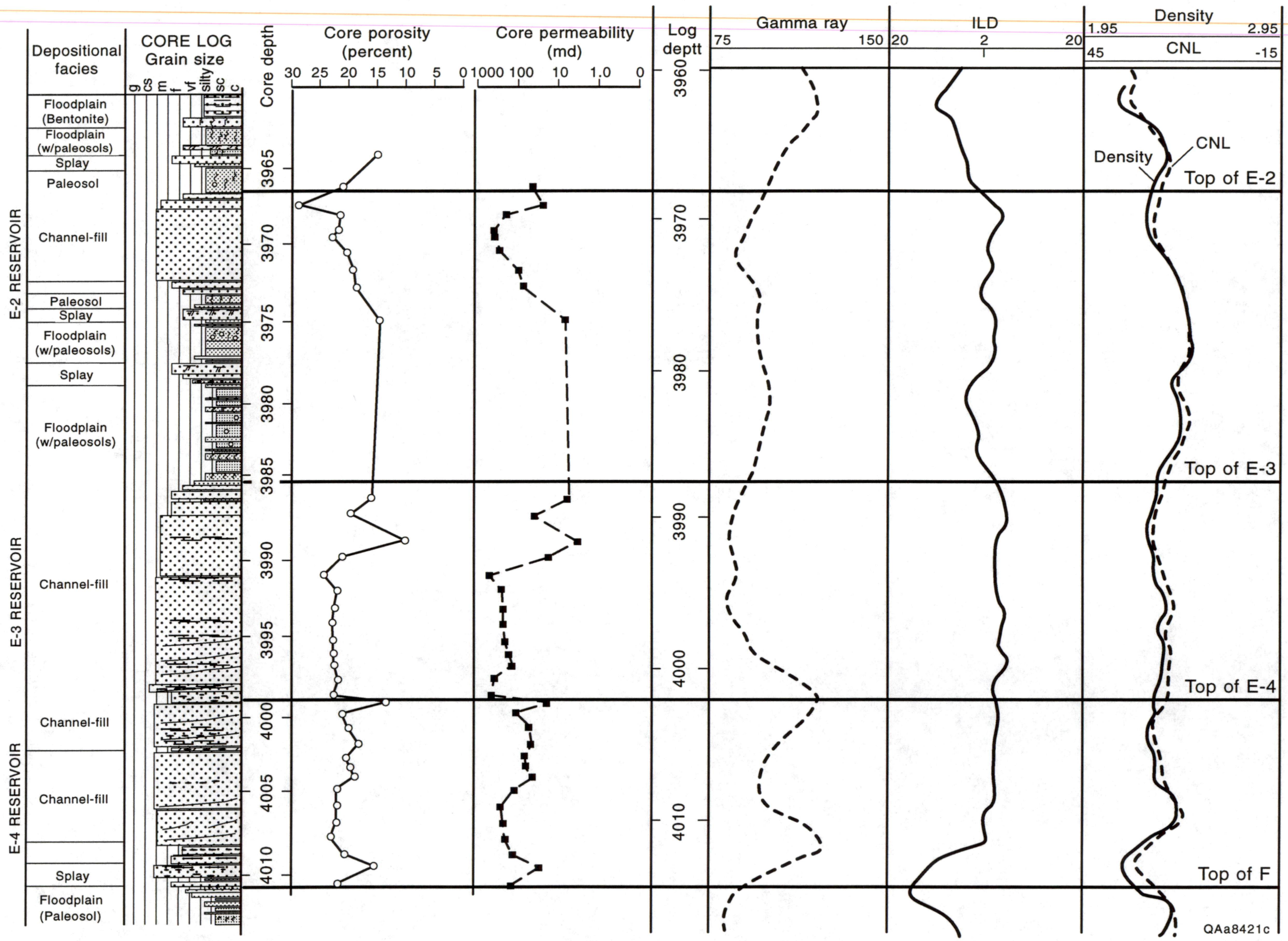


Figure 42. Core graphic log; porosity and permeability data; and gamma-ray, induction, and porosity logs, T. B. Slick 231:149 well. See Figure 24 for legend explanation.

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

Analysis of Modern Logs

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

The workflow scheme for analyzing modern logs includes depth shifting core data to wireline depths, determining a bulk shale volume indicator (Vsh), and developing a porosity algorithm. Based on correlation with other wells, and the significant presence of radioactive lithics within the sandstone, it is determined that the gamma-ray log is not a good indicator of shale. Instead, the neutron log (CNL) is used as a shale indicator to calculate the shale fraction. The following equation is used to determine the shale volume:

$$Vsh = ((CNL * (CNL - CNL\ sand)) / DI)^{**}\ 0.5 \qquad (10)$$

where

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

Vsh = bulk shale volume

CNL = CNL log value

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

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

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

Porosity can be determined from the standard density-neutron crossplot applying a bulk volume shale correction. When calculating porosity a clay density of 2.124 g/cc and a neutron clay response of 0.534 were chosen. These values were determined from density and neutron logs matching at the peak depth where the pure shale volume (100% of shale) is presented. It is noted that the value for the density of clay (2.124) corresponds to the published value of 2.120 for montmorillonite. The value for neutron clay (0.534) is not very much different from the published values of 0.6 for montmorillonite, and, this value is very close to the published value of between 0.519 and 0.500 for wet clay. Correction for bulk volume shale is critical in determining correct porosity. The computed results for porosity without shale correction and shale corrected crossplot porosity are compared with core porosity in Figure 43. Figure 43 clearly shows that shale corrected crossplot porosity better represents core porosity than uncorrected crossplot data, and the uncorrected data predicts overly optimistic porosity values.

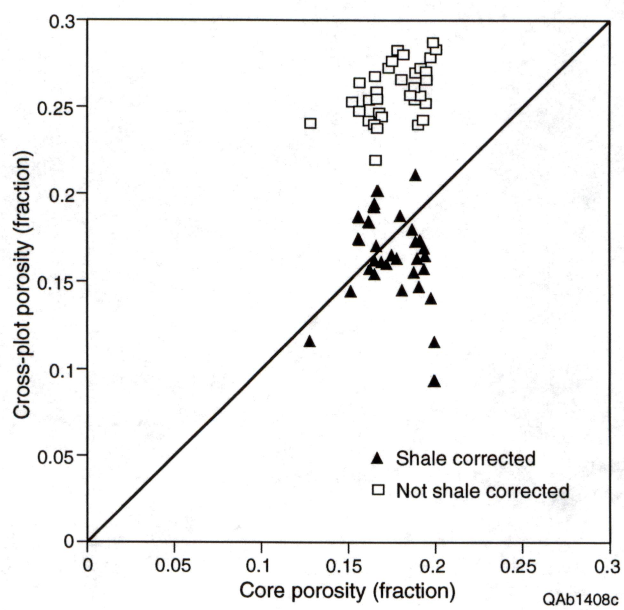


Figure 43. Comparison of shale-corrected and uncorrected cross-plot porosity versus core porosity.

Analysis of Old Logs

Resistivity measurements are used to obtain porosity from wireline logs before porosity logs were invented. Several steps are needed to ascertain the resistivity derived porosity. These steps involve calculating Vcl in order to compensate for the conductivity of shale and then calculating a compensation for the effect of mud filtrate invasion.

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

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

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

$$SSP = ((0.133*Tr)+60)*\log(Rw/Rmf) \tag{12}$$

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

$$Vcl = 1-(SP/SSP) \tag{13}$$

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

$$Rz = 1/((0.1/Rw)+(0.9/Rmf)) \tag{14}$$

Resistivity porosity is then derived from the equation below.

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

Fluid Saturation Modeling

Formation Resistivity Factor

The saturation exponent applicable in Rincon field is taken as 1.7. Reported values range from 1.64 to 1.8 and average 1.7 (Table 6). This data source is limited, but values do not range significantly and the result of saturation calculation is not sensitive to saturation exponent in clean sandstone.

Table 6. Representative saturation exponents from the Frio Fluvial-Deltaic Sandstone play.

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

(*from Dewan, 1988; ** from Ambrose and others, 1992).

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

Formation resistivity factor (FRF) was analyzed from lab measurements. Fourteen measurements were obtained to determine the character of formation resistivity factor. The data are representative of the total range of pay as defined by porosity and permeability. Porosity ranges from 9 percent to 32 percent, and permeability ranges from 0.4 md to 747 md. Measured FRF values are also consistent with published data, ranging from 12.5 to 45.8. Converting FRF to cementation exponent values, assuming in the Archie equation a = 1, the values range from a minimum of 1.67 to a maximum of 2.4 and have a median of 1.81 (Table 7). This median is consistent with the average published cementation exponents in Table 7.

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

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

A robust multiple nonlinear regression model for the prediction of FRF was developed. The model in equation (16) predicts FRF with porosity and permeability as input independent

Table 7. Special core analysis and descriptive statistics for core samples in Rincon field.

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

variables. The correlation is strong, displaying a multiple r of 0.95 and an F statistic of 53 compared to a significant F of 2.3×10^{-6}. The predictive capability is illustrated in Figure 44. Actual versus predicted values cluster closely around the 1-to-1 line with the exception of one data outlier. This outlier is a data point that displays a higher FRF for the measured porosity and permeability.

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

where porosity is a fraction and permeability is in millidarcys.

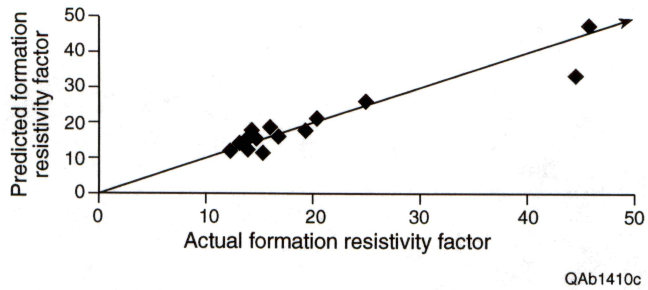


Figure 44. Results of the multiple nonlinear regression model for predicting FRF. The strong predictive capability is displayed by the clustering of the data around the 1-to-1 line.

Capillary Pressure Modeling

The primary objective of the mercury-injection capillary pressure measurements was to determine the distribution of pore throat sizes present in each sample, and to ascertain any differences in pore types among the various rock types identified from core description and evaluation of conventional core analysis data. Thin sections were prepared for each sample selected for capillary pressure studies to provide visual description of pore geometries and estimates of pore sizes. The mercury-injection technique is the most commonly used and fastest method of capillary pressure measurement, and 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.

Initial connate water saturation was modeled from capillary pressure data as a function of porosity, permeability, and height above free water. From exploratory statistical data analysis it was found that both porosity and permeability, as well as height above free water, controlled initial water saturation. The relationship between initial water saturation and permeability and height above free water is nonlinear, whereas the relationship between initial water saturation and porosity is linear. Multi-nonlinear regression was applied to develop an initial water saturation function. The character of this function is illustrated in Figure 45. The multi-nonlinear equation is statistically robust, having a correlation coefficient (r) of 0.88. The utility of this equation is that this equation can be applied when, because of lack of data, the Archie equation cannot be applied.

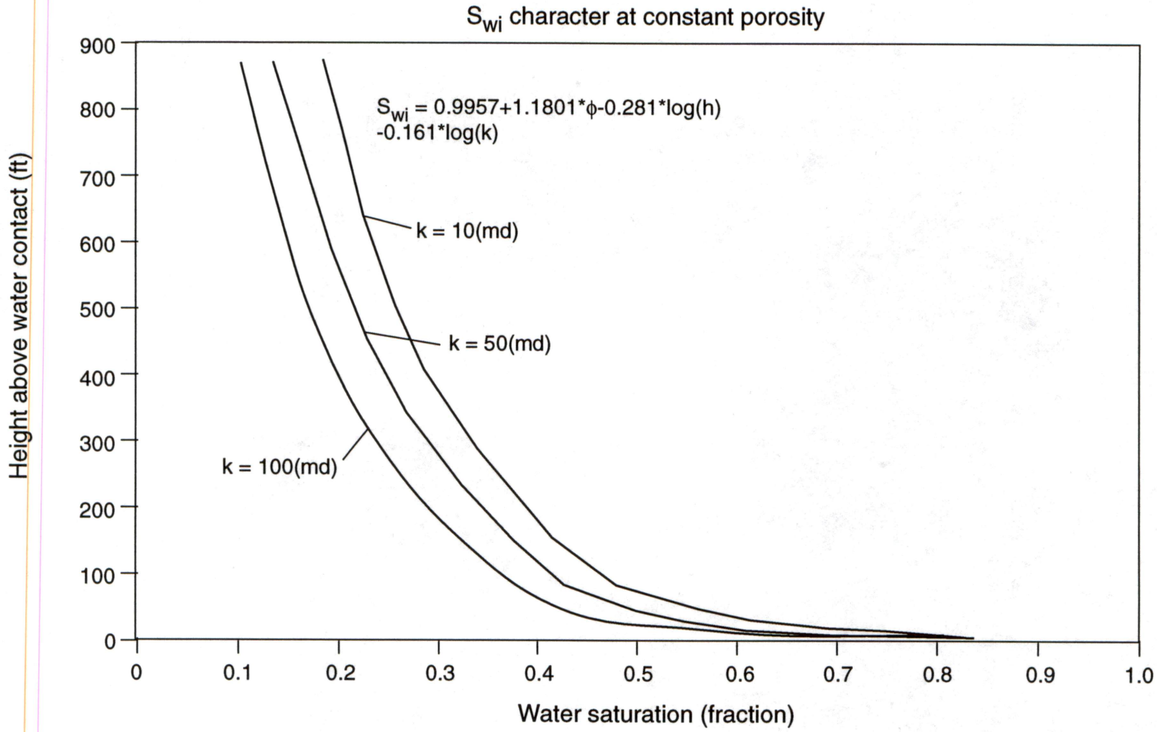
Residual Oil Saturation

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

Residual oil saturation can be characterized as low with a long tail on the high side. The mean and median are nearly identical at 28.8 percent, indicating a strong central tendency. The standard deviation is a low 9 percent, although the range is large (48 percent). The large range is due to a high outlier value of 62.5 percent. Because the data sample is small, it cannot be determined if this high data point is valid. The long tail is evident in the high skewness value of 1.74 and on the histogram shown in Figure 46.

Identification of Strategies for Optimizing Reserve Growth

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



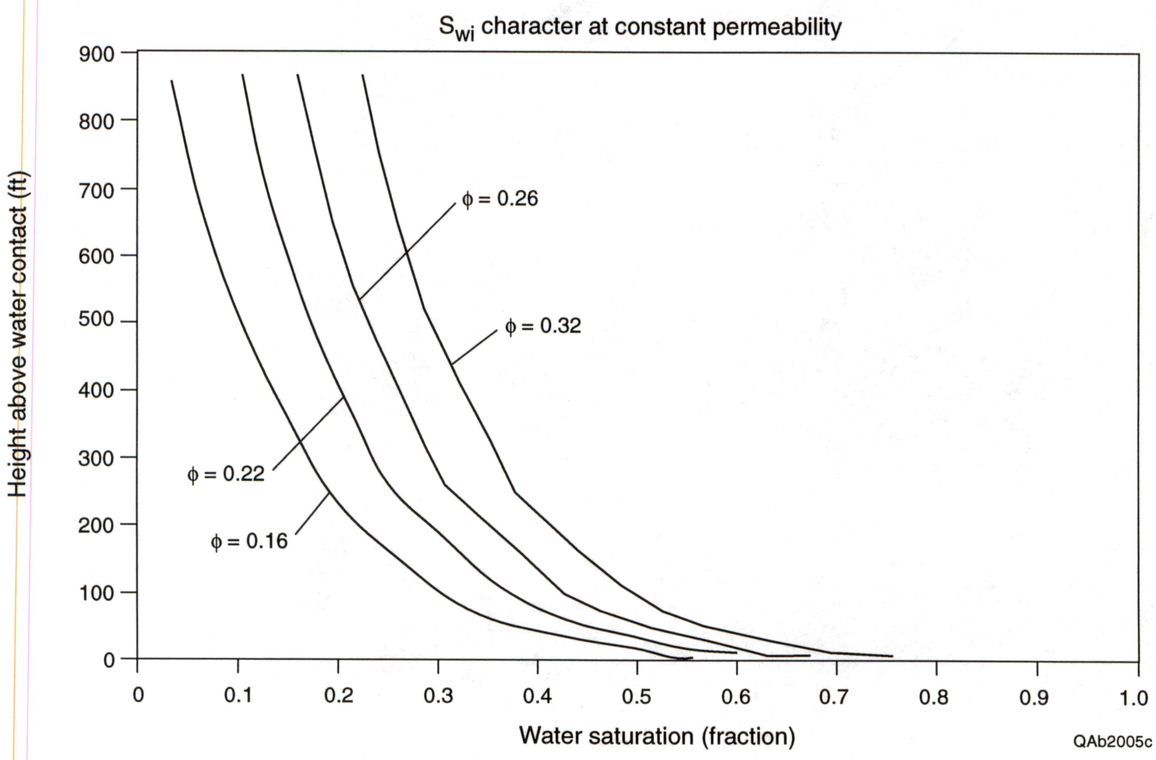


Figure 45. Initial water saturation is modeled from a multi-nonlinear regression equation with porosity, permeability, and height above free-water as the independent variables.

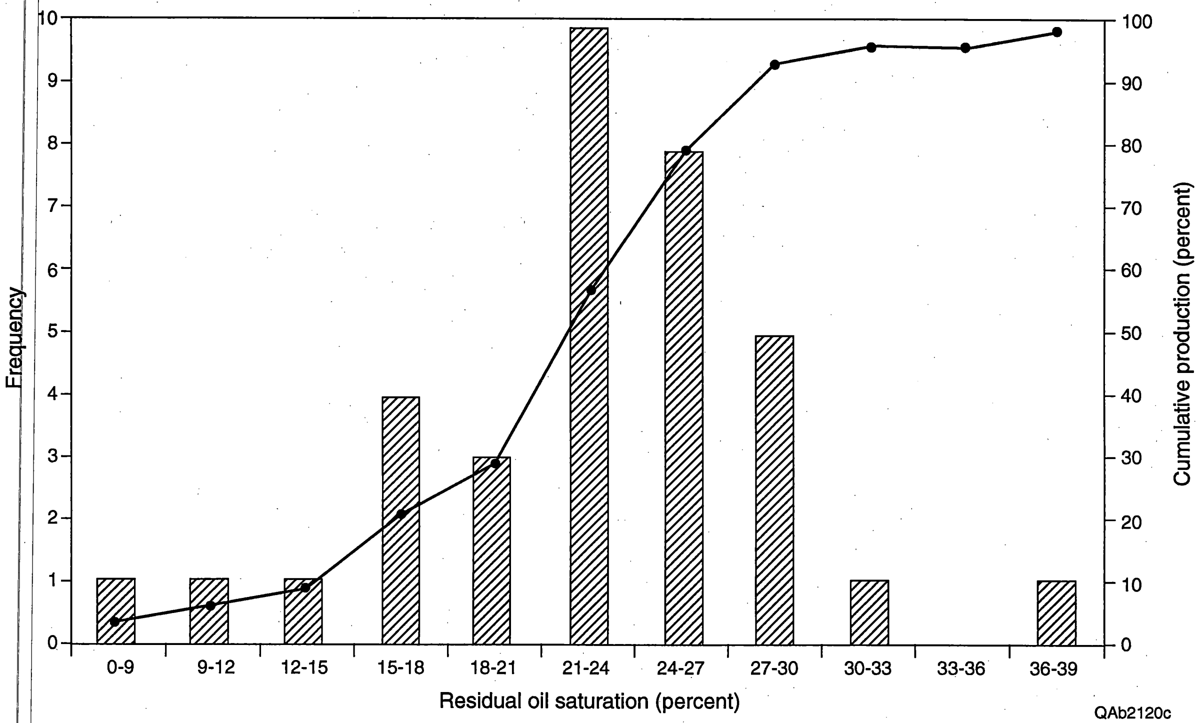


Figure 46. Residual oil saturation measured from core flood tests indicates a wide range of possibilities due to high and low tails on the distribution.

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

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

Drainage radii of productive wells 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 is 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 $S_o\phi h$ 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.

The result of the above integration process is a map for each flow unit of remaining mobile oil, as well as information regarding effective drainage radii for each flow unit. This information can be combined to determine areas of remaining mobile oil that can be drained by existing well bores (recompletion opportunities) and those areas that must be reached with new well bores through geologically targeted infill drilling. These opportunities can be ranked in terms of estimated profitability by calculating the volume of oil recoverable from each possible recompletion or infill and dividing by the cost of the completion.

Many single completions can drain large areas because they are situated where vertically adjacent flow units are in good communication, thereby necessitating the completion of only a short interval of the well bore. Other single completions may drain comparatively small volumes because that particular flow unit is internally heterogeneous. In many cases of reserve-growth opportunities in mature fields, an opportunity requiring infill drilling to reach a single zone may not be economically justifiable on its own. However, an infill well that is designed such that it targets that opportunity and another opportunity in a similar area but in a different flow unit may rise above the economic hurdle. As a consequence, the best strategy for optimizing reserve-growth opportunities is to overlay maps of infill drilling opportunities and plan a directional infill well, if necessary, that penetrates as many opportunities as feasible. An extreme case of this might occur when a single flow unit contains many laterally isolated, untapped, or incompletely drained compartments that are adjacent. In this case, a horizontal, or nearly horizontal, well might be planned that economically targeted just a single flow unit.

Conclusions

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

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

The economic viability of potential infill wells can be improved by targeting multiple infill opportunities with a single well bore. This can be accomplished by overlaying mapped opportunities from different flow units to identify a vertical string of opportunities or by joining adjacent opportunities within a single flow unit through use of a horizontal well bore.

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

T-C-B FIELD RESERVOIR STUDIES

by P. R. Knox

Introduction

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

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

The interpretation of reservoir compartmentalization has been presented to the field operator during the third project year, along with specific recommendations for recompletion and infill drilling opportunities. Because of various economic and operational considerations, only one recompletion has been done. This opportunity, evaluated as having moderate risk, is currently producing at economic rates but high water cut. Data and some structural interpretation from a recent 3-D seismic survey have been made available to the Bureau, and we will expend additional efforts to incorporate this valuable information to clarify the risk of opportunities identified during the third project year.

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

Location

Tijerina-Canales-Blucher field is located in the northern half of the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) oil play, about 55 mi southwest of Corpus Christi, and it straddles the border between Kleberg and southern Jim Wells Counties (Fig. 23). The field lies in a structural low between large rollover anticlines in the Seeligson and La Gloria fields to the northeast and southwest, respectively. Movement on the Sam Fordyce Fault, a part of the regional Vicksburg Fault Zone, and subsidiary synthetic and antithetic faults, has generated a fault-segmented rollover structure in the lower Frio reservoir section. Accumulation of most of the sediment within the middle Frio postdates most of the fault movement, creating a low-relief unfaulted (to subtly faulted) anticline slightly offset from the crest of the underlying rollover structure.

The area selected for study is a contiguous 4,800-acre block, located at the southwest edge of the field and operated by Mobil Exploration and Producing, U.S. The block is primarily composed of the 3,500-acre Blucher lease, which is adjoined by the smaller Blucher B, A. A. Seeligson, Lobberecht, and Stewart & Jones I and II leases (Fig. 47). Mobil has supplied well log, core, and production data for more than 80 wells on this lease block.

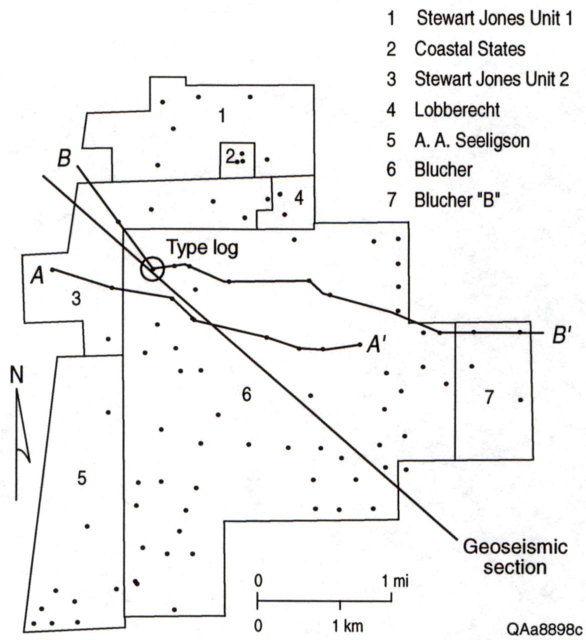


Figure 47. Map of study area in T-C-B field showing lease boundaries and approximate location of geoseismic section (Fig. 50).

Development History

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

The area of T-C-B field selected for detailed study, the western Blucher portion, was discovered by Shell in 1939 and subsequently sold to La Gloria Corporation in 1942. La Gloria operated the field until Mobil purchased the leases in 1967. Recent deeper drilling by Mobil in the late 1980's targeted complex fault blocks interpreted from 2-D seismic data. During 1994, 3-D seismic data were gathered over the Mobil leases, and processing was completed in early 1995. This data will improve the understanding of T-C-B reservoirs and foster further activity within the field. 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

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

Frio sediments in the vicinity of T-C-B field were deposited by the Norias deltaic and Gueydan fluvial depositional systems that filled the axis of the Rio Grande structural embayment (Fig. 48). The location of T-C-B field lies near the boundary of these two depositional systems. During early Frio times, the Norias delta occupied the T-C-B area. Because of continuous progradation, the Gueydan fluvial system (equivalent to the upper delta plain of the Norias system) eventually encroached on the T-C-B area from the northwest, occupying the area throughout the middle Frio time.

Productive reservoir sandstones in T-C-B field range in depth from 5,500 to 8,000 ft and lie within the middle and lower members of the upper Oligocene Frio Formation and the upper part of the lower Oligocene Vicksburg Formation, as shown in the field type log (Fig. 49). 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.

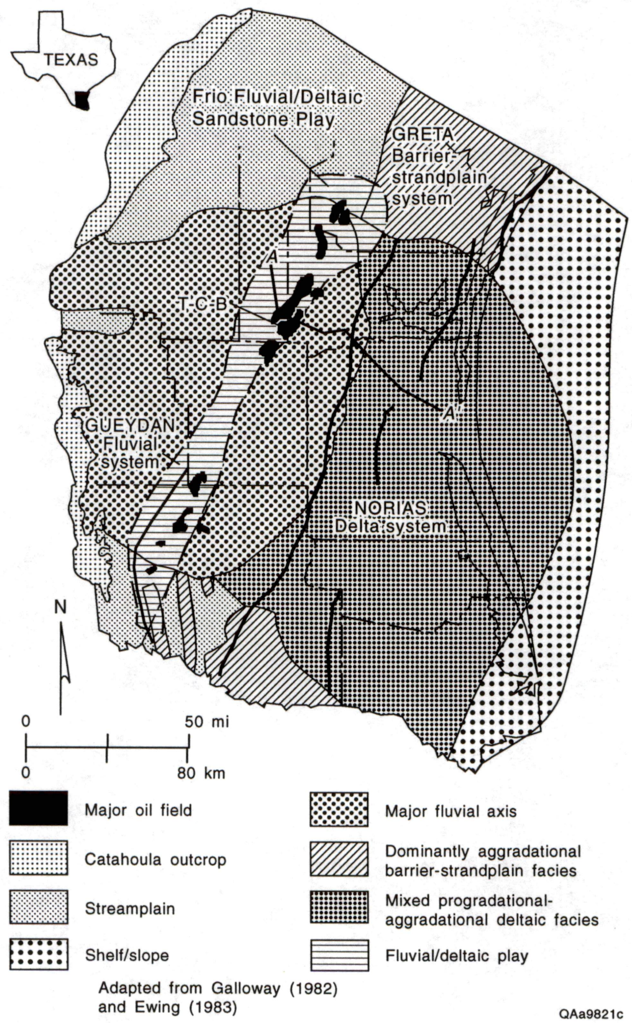


Figure 48. Location of Tijerina-Canales-Blucher (T-C-B) field within the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) Play in South Texas. Also shown is the position of T-C-B field with respect to the Norias delta and Gueydan fluvial depositional systems of Galloway (1982). Cross section A–A′ is shown in Figure 52.

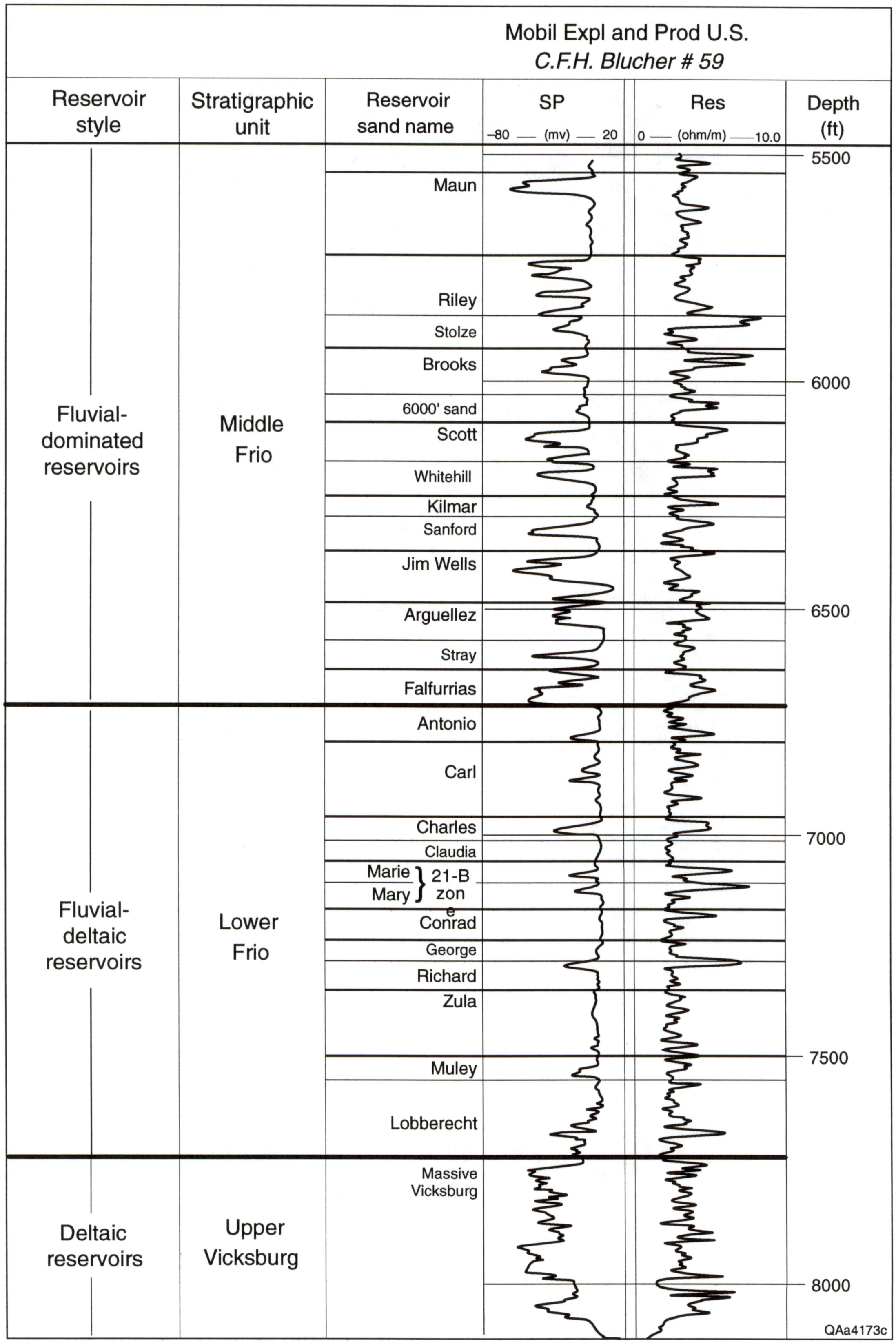


Figure 49. Representative log from T-C-B field illustrating generalized stratigraphy and nomenclature of productive reservoir sandstones.

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 (Fig. 50) 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.

Methodology

The primary objective in T-C-B field for year 3, that of identifying specific reserve-growth opportunities in selected reservoirs, required advanced technology reservoir characterization that integrated geological and engineering methods (the methodology used to select reservoirs for detailed study is documented in McRae and others, 1994). An important technical goal was to apply observations from a previous outcrop study of Cretaceous fluvial-deltaic sandstones of the Ferron Formation of central Utah. This study, funded by the Gas Research Institute and various industrial associates, concluded that reservoir architecture and heterogeneity varies systematically within a fourth-order genetic unit (Barton, 1994), presumably as a consequence of systematic changes in accommodation rate. The following two sections briefly review both the observations from the Ferron outcrop study and the general reservoir characterization methods used to investigate the Scott/Whitehill reservoir interval of T-C-B field.

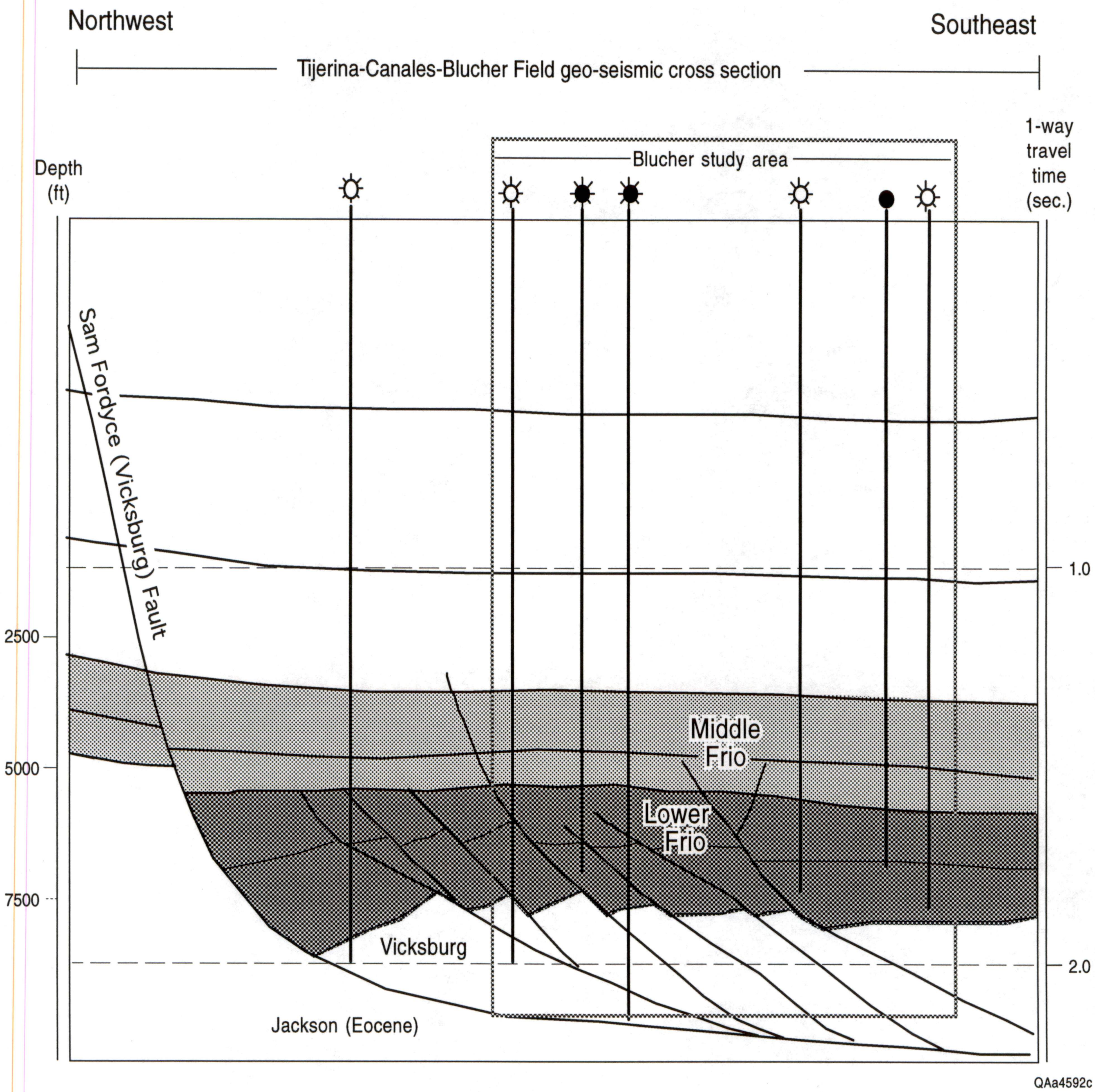


Figure 50. Northwest-to-southeast geoseismic dip section across T-C-B field illustrating the general structural setting of Frio and Vicksburg reservoir sections. The base of the middle Frio is a significant unconformity separating structurally complicated reservoirs below from less faulted reservoirs above. Seismic interpretation provided by Mobil Exploration and Producing, U.S. See Figure 47 for approximate location of section.

Outcrop-Based Models for Predicting Reservoir Architecture

The Upper Cretaceous (Turonian) Ferron Sandstone of central Utah was deposited in a fluvial-deltaic depositional system that existed on the west margin of the Cretaceous Interior Seaway (Barton, 1994) and carried sediments from the rising thrustbelt in the west to the rapidly subsiding foreland basin to the east. Total accommodation rates for the Ferron are similar to those for the Frio Formation in the Texas Gulf Coast: the Ferron spans 1.6 m.y. and is 800 ft thick, whereas the Frio ranges from 800 to 4,000+ ft and accumulated in a similar time span. Gardner (1991) divided the Ferron into seven fourth-order genetic sequences, GS 1 through GS 7 (Fig. 51a), each bounded by a marine flooding surface and being equivalent to a parasequence, as defined by Van Wagoner and others (1988). These genetic sequences vary from strongly progradational or seaward stepping in the lower portion (GS 1 and 2), to aggradational or vertically stacked in the middle (GS 3 and 4), to retrogradational or landward-stepping at the top of the depositional cycle (GS 5, 6, and 7).

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

Distributary-channelbelt deposits that formed during the strongly seaward-stepping portion of a depositional cycle (GS 2), at which time the rate of sediment influx was greater than the rate of generation of accommodation space, are typically narrow and few in number, and consequently cover little area in map view (Fig. 51b). Internally, these channelbelts consist of sandy, vertically amalgamated channel deposits dominated by trough-fill cross-stratified lithofacies of basal channel deposits. The base of individual channel deposits commonly contains a lag of dispersed and rounded mudstone and sandstone clasts, creating a layer of slightly reduced permeability at the contact between vertically adjacent channels. Low-permeability lithofacies from the upper portions of individual channel deposits, such as finer grained ripple

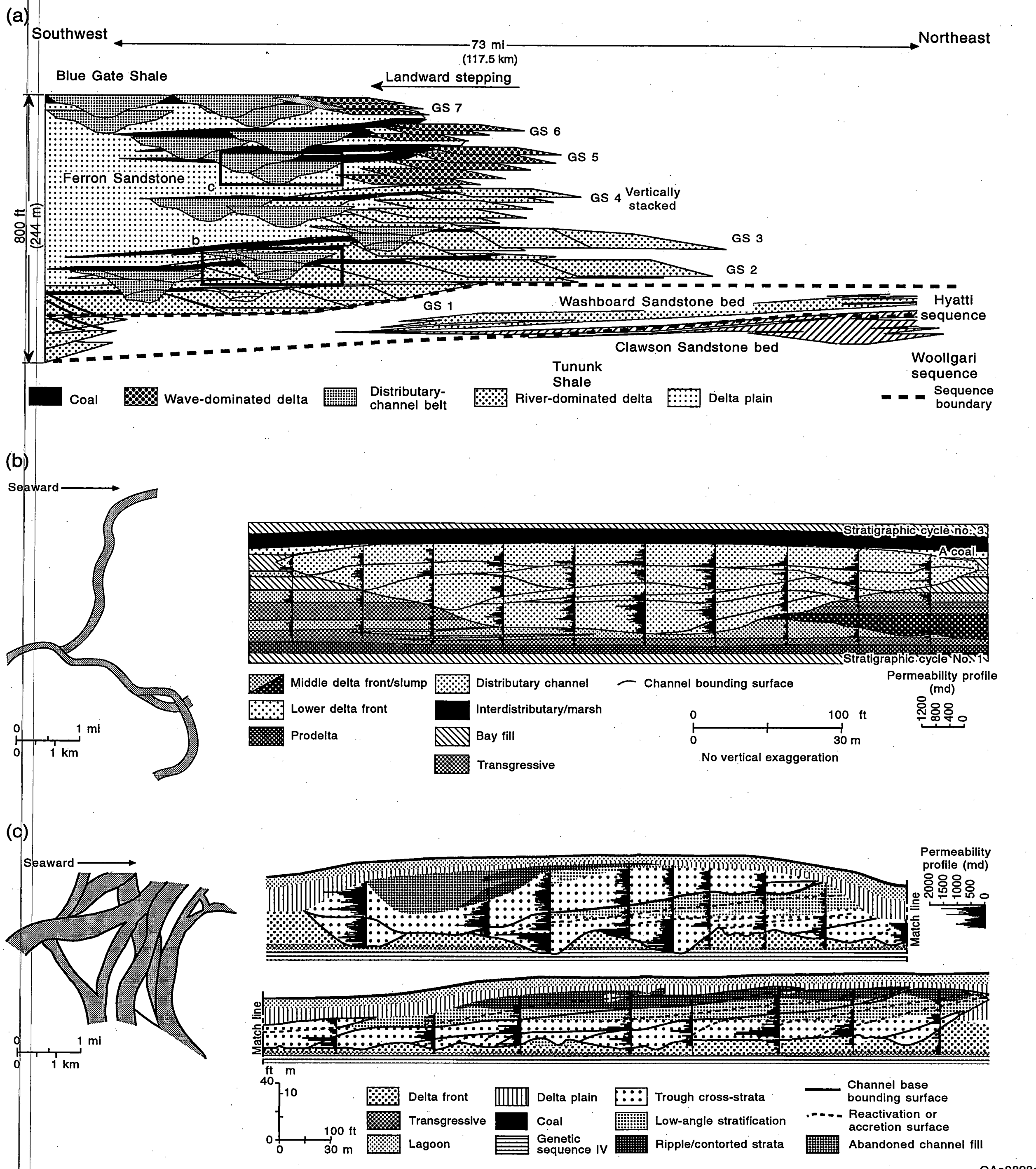


Figure 51. Genetic stacking pattern and architecture of the Cretaceous (Turonian) Ferron Sandstone of central Utah. (a) Stacking pattern for the Ferron 3rd-order depositional unit, composed of a depositional cycle of 4th-order units. Note locations of distributary channel fills detailed in (b) and (c). (b) Map view architecture and internal lithofacies of distributary channel fills in the low-accommodation seaward-stepping GS 2 4th-order unit. (c) Map view architecture and internal lithofacies of distributary channel fills in the high-accommodation landward-stepping GS 5. From Barton (1994).

strata and siltstones, are uncommon, having been removed by erosion during the incision and filling of subsequent channels. Barton (1994) ascribed the dominance of erosion over deposition in these channels, and thus their relative internal homogeneity, to the low accommodation rates under which they were deposited. The straight, narrow configuration of these channelbelts is also a consequence of low accommodation in that the channel system, previously meandering in part, must stretch to cover the increasing distance to the seaward-stepping distributary mouth, eliminating the tendency toward lateral migration and meandering. Distributaries are few because there is no opportunity for the channel to avulse, having never built substantially higher than the surrounding delta plain.

In contrast, distributary-channelbelt deposits formed during the landward-stepping portion of the Ferron depositional cycle, in which the rate of accommodation exceeded the rate of sediment influx, are broader and more numerous, covering a greater percentage of area in map view than those of the seaward-stepping unit. Internally, channelbelts are more lithologically heterogeneous, containing nearly complete vertical channel deposit successions including trough cross-stratification, low-angle inclined stratification, rippled beds, and abandoned channel-fill mudstones (Fig. 51c). Channel bases are commonly draped by a lag deposit containing abundant deformed mudstone clasts that form a very low permeability layer between channel deposits that are in sandstone-on-sandstone contact. This depositional style indicates laterally migrating channels constrained within topographically high levee systems and flanked by large areas of low-lying floodplain, leading to frequent channel avulsion. This is consistent with the anticipated morphodynamic response of a distributary to rising base level, in which a channel of fixed length must increase its sinuosity as the distributary mouth steps landward. More complete preservation of individual, internally heterolithic channel deposits is a consequence of higher accommodation rates, in which subsequent channels do not cut as deeply into previous channel deposits because of a larger rise in base level (relative sea level) in the intervening period.

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

Reservoir Characterization Methods

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

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

Genetic Stratigraphic Setting of the Scott/Whitehill Interval

A dip-oriented stratigraphic cross section stretching from several miles updip of T-C-B field to approximately 60 mi downdip (Fig. 52) was prepared so that these reservoirs could be placed within a depositional and stratigraphic framework. The character of spontaneous potential (SP) and resistivity logs was used to imply general depositional setting of Frio units in the cross section and identify shales that represented major (third- and fourth-order) marine flooding events in the downdip marginal marine setting. Log markers that bound the Scott/Whitehill reservoir interval above and below were correlated from an implied upper delta-plain position at T-C-B field to fourth-order marine flooding surfaces in the downdip area (Fig. 52). Thus, because the interval is bounded by the nonmarine equivalent of flooding surfaces, it reflects a cycle of deposition beginning with progradation, leading to aggradation, and terminating with retrogradation.

Architecture of Reservoirs within the Scott/Whitehill Depositional Cycle

The general stratigraphy and architecture of the Scott/Whitehill reservoir interval can be deduced from careful well log correlation, and are shown in a dip-oriented stratigraphic cross section through the study area (Fig. 53) and a series of net sandstone maps (Fig. 54b,c, and d). The interval is divided into four fifth-order genetic units by laterally continuous surfaces that may correspond to more minor marine flooding events. Narrow to broad dip-oriented channelbelts represent major reservoir compartments. Each fifth-order genetic unit ranges in thickness from 20 to 50 ft, with each successive unit generally thickening from the lower Whitehill 20 ft at the base through the upper Scott (50 ft) (Fig. 53) at the top. Assuming equivalent time spans for each unit, this would suggest persistently increasing rates of accommodation. In addition, the percentage of net sandstone also increases upward.

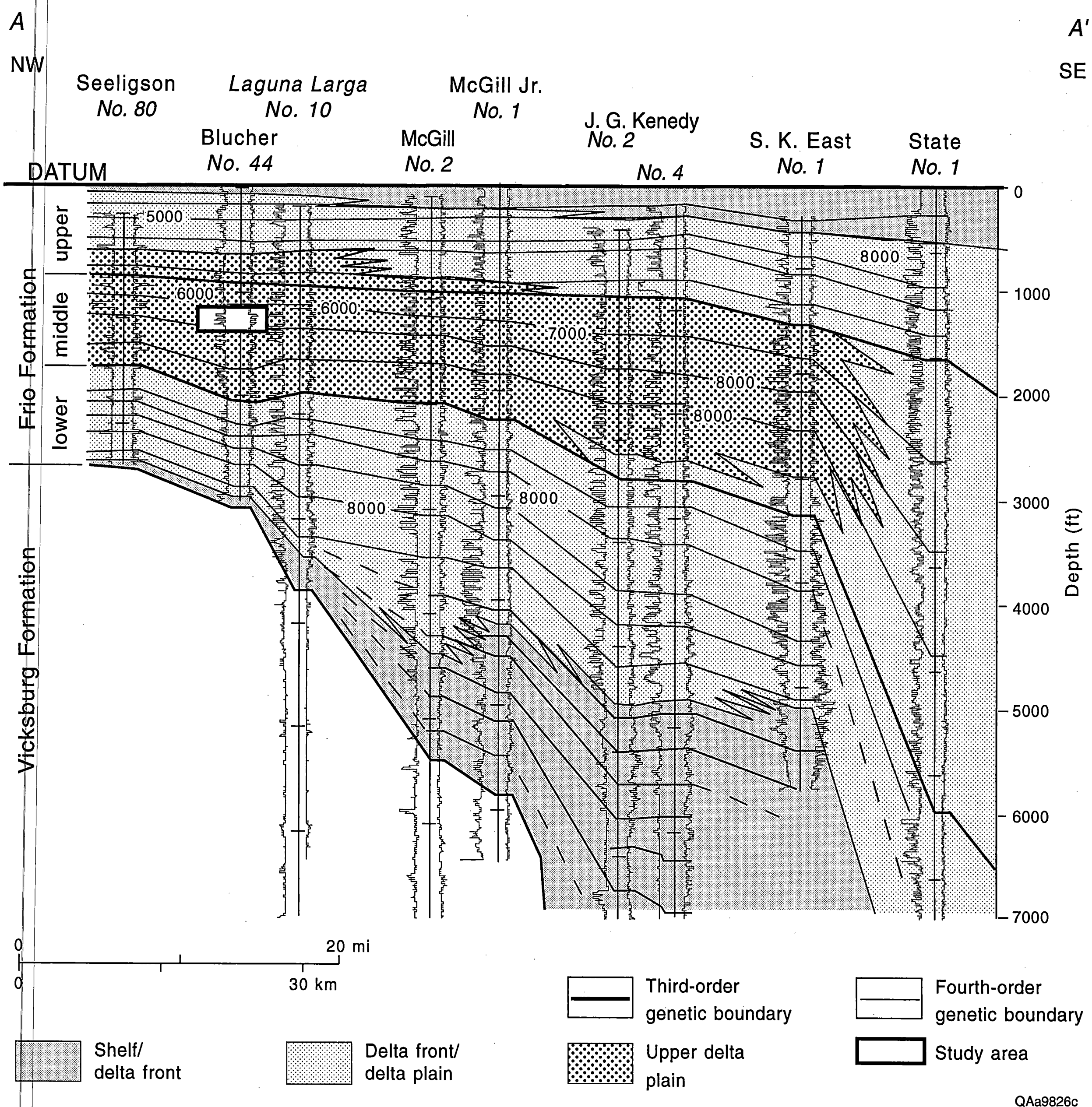


Figure 52. Dip-oriented stratigraphic cross section A–A′ through the Frio Formation from updip of T-C-B field down to the present coastline. The Frio consists of three 3rd-order depositional units, each containing 4th-order units. See Figure 48 for location of cross section.

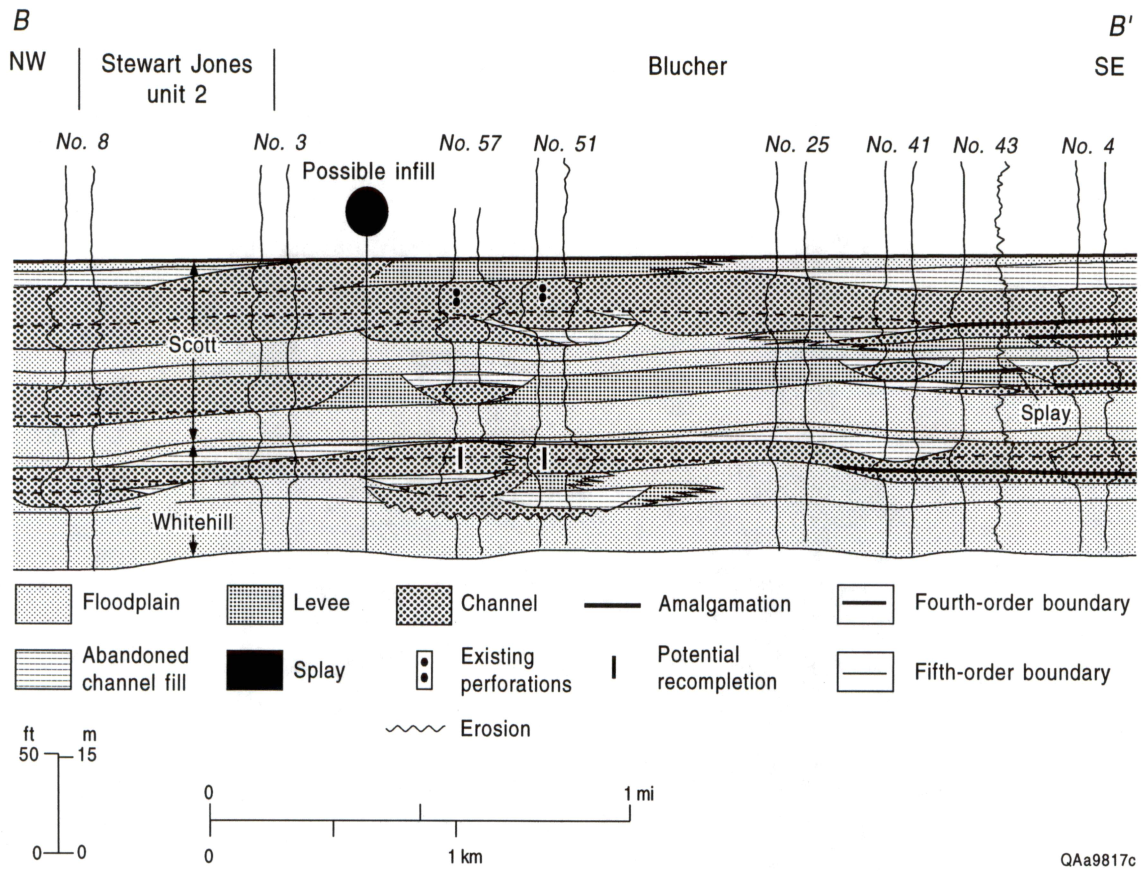


Figure 53. Dip-oriented stratigraphic cross section B–B′ of the Scott/Whitehill 4th-order reservoir interval, which contains at least four 5th-order depositional cycles. These are, from the top down, the upper and lower Scott and the upper and lower Whitehill reservoir intervals. See Figure 54a for location of cross section.

Sandstones within the Scott/Whitehill interval are draped across a subtle south-plunging structural nose (Fig. 54a). They display symmetrical, blocky, or upward-fining log patterns, range in thickness from 3 ft to more than 50 ft, and are separated by siltstones and mudstones of similar thickness. Thicker sandstones consist of amalgamated individual channel deposits, each of which reaches a maximum of 20 ft. The dominance of a blocky and upward-fining log pattern, the absence of microfauna, and the regional setting all indicate that these sandstones were deposited in an upper delta-plain fluvial setting. Depositional facies identified on the basis of log character include sandy point-bar channel deposits, silty to muddy abandoned channel fill, rare sandy splay deposits, silty levee deposits, and fine-grained floodplain mudstones (Fig. 53).

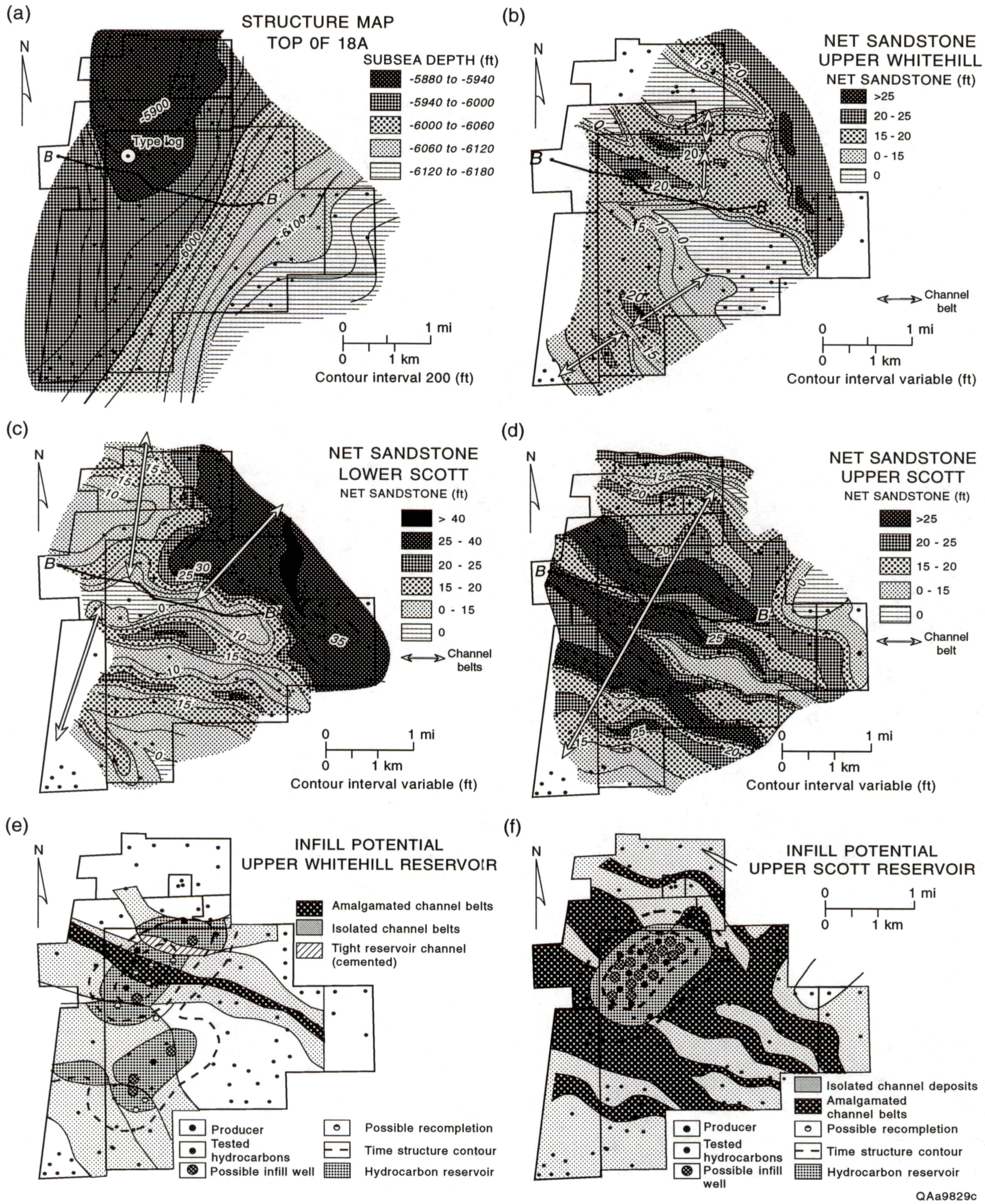


Figure 54. Structure, net sandstone, and infill-potential maps, Scott/Whitehill reservoirs. (a) Structure map on the 4th-order flooding surface that forms the upper boundary of the interval. Cross section B–B′ shown in Figure 5. (b) Net-sandstone map of the upper Whitehill 5th-order interval. (c) Net-sandstone map of the lower Scott 5th-order interval. (d) Net-sandstone map of the upper Scott 5th-order interval. (e) Infill potential map of the upper Whitehill reservoir interval. (f) Infill potential of the upper Scott reservoir interval.

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

The overlying upper Whitehill unit, in the seaward-stepping to vertically stacked portion of the depositional cycle (low to intermediate accommodation), consists of three relatively narrow (1 mi wide) but generally thin fluvial channelbelt deposits (Fig. 54b) separated by large areas of floodplain mudstone. These channelbelts trend in a general dip orientation and are typically less than 20 ft in thickness. Thicknesses in excess of this are the result of vertical stacking of broader channelbelts (1 mi wide) in the middle or upper portion of the interval on top of very narrow channelbelts (0.3 mi wide) at the base of the interval. The comparatively broader channelbelts in the middle and upper portion are each interpreted to contain two to three incomplete, vertically amalgamated channel deposits, each ranging from 5 to 10 ft in thickness. Abandoned channel mudstones are most common in the uppermost channel deposits.

The next highest unit, the lower Scott, in the vertically stacked to landward-stepping portion of the depositional cycle (intermediate to high accommodation), is similar to the upper Whitehill except that channelbelts tend to be broader (1.5 mi) (Figs. 53 and 54c). In addition, the narrow channelbelts that occur at the base of the interval are restricted to the northeastern portion of the study area, where an unusually thick accumulation of channel deposits may have resulted from subtle paleotopographic control. Overall, the lower Scott contains a greater volume of sandstone than the underlying upper Whitehill interval.

The upper Scott reservoir interval, at the top of the fourth-order unit and, thus, in the strongly landward-stepping portion of the depositional cycle (high accommodation), differs markedly from the underlying intervals in that it is distinctly thicker and sandier, with a single broad channelbelt (3.5 mi wide) covering the entire study area, which consists of vertically amalgamated channel deposits (Figs. 53 and 54). Dip-oriented bodies of sandstone thicknesses in excess of 20 ft (Fig. 54d) are the result of two or three vertically amalgamated channel deposits, each separated from the other by abandoned channel mudstones, finer grained upper channel-fill deposits (presumably rippled silty sandstones of an upper point bar setting), or possibly thin layers of mudclast rip-up conglomerate at the bases of channels. The uppermost portion of the upper Scott interval is dominated by siltstones and mudstones of abandoned channel, levee, and floodplain deposits (Fig. 53).

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

Scott/Whitehill Internal Heterogeneity

Whereas the gross architecture of the reservoir compartments (channelbelts) could be identified with reasonable accuracy with well log control, the heterogeneity within compartments is potentially much finer than the spacing between wells, being, as it likely is, controlled by the boundaries between individual channelforms. Tentative plans have been established to use the 3-D seismic data recently provided by the operator to image individual channelforms, as was done by Bureau researchers at Seeligson field (Hardage and others, 1994). Short of an involved and expensive seismic study, the most reliable measure of internal heterogeneity is production performance. The relative size of areas drained in a series of reservoirs will be a measure of the internal complexity of the reservoirs, assuming similar drive mechanisms and fluid viscosities.

We have produced compartment history maps (Figs. 54e and 54f) for the upper Whitehill and upper Scott intervals, documenting compartment boundaries and past completions. The following discussion summarizes the production history of the two reservoirs and estimates drainage areas for these completions.

Well control, limited 2-D seismic data, and preliminary interpretations of 3-D seismic indicate two areas of subtle structural closure (Fig. 54e) on the more prominent structural nose (Fig. 54a) in the study area. Production from the Scott/Whitehill interval is limited to gas in the upper Whitehill and oil in the upper Scott.

The upper Whitehill has produced from two wells, one on the northern structural crest and the other farther to the north in which perforations were structurally below the documented gas/water contact on the structural crest (Fig. 54e). Resistivity measurements indicate moderate gas saturations in the southern structure, but no tests of this potential accumulation have been made. Mapping of channelbelts and evidence of tightly carbonate cemented sandstone in one well suggest that the northernmost of the two completions was stratigraphically isolated from the structural crest. Evidence from wells postdating production indicates that the crestal completion drained approximately 40 acres. At present, insufficient data are available on the other well to document drainage area.

Eight wells have produced oil from the upper Scott on the main structural crest (Fig. 54f). Cumulative production has ranged from less than 1,000 bbl to more than 54,000 bbl per well (Table 8). Initial water cuts have varied widely and have been independent of structural position and offset production history, indicating a lack of communication between well locations (Table 8, Fig. 55). Preliminary volumetric analyses suggest that completions have drained areas ranging from less than 1 acre to approximately 5 acres, significantly less than the completion in the Whitehill. Initial calculations indicate that despite completion at a 20- to 40-acre spacing, and the fact that all current completions are idle or nearly watered out, less than 10 percent of the original oil in place has been recovered from the Scott.

Table 8. Initial potential and cumulative production data for completions within the upper Scott zone.

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

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

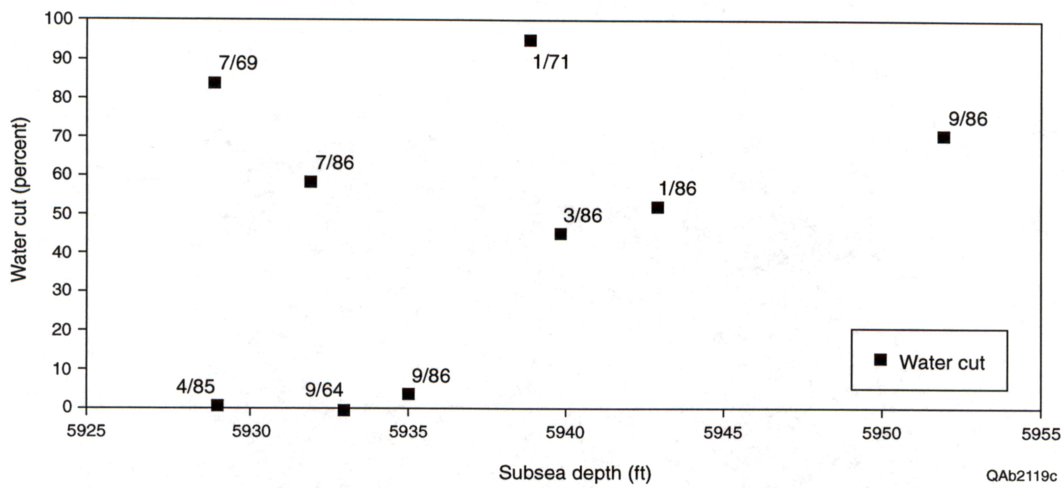


Figure 55. Crossplot of initial water cut versus depth to top of reservoir, upper Scott zone. The completion date is also annotated to document the possible effects of offset production. Note the very poor correlation of water cut versus depth or completion date, indicating laterally isolated compartments.

Reserve-Growth Opportunities

Because of sparse past development of the upper Whitehill interval, numerous recompletion opportunities exist, in addition to possible infill locations. Figure 56 shows the location of 16 recompletion opportunities, which are listed in Table 9 and accompanied by a qualitative risk value and 5 infill drilling opportunities. The operator recently recompleted one well rated as moderate risk due to its proximity to a well that has produced 5 billion cubic feet (Bcf) of gas from the upper Whitehill. The recompleted well flowed moderate amounts of gas (268 Mcfd) but also is producing high volumes of water (200 bpd). The present rate is economic, despite the high water production. Three low-risk recompletions remain untested due to a number of operating considerations such as current production from other zones in the wellbores. Because the drive mechanism in the upper Whitehill is a combination pressure depletion/water drive, cumulative production for proposed recompletions is anticipated to approach but not exceed 5 Bcf for each low-risk recompletion. Risk for identified infill opportunities has not been assigned, pending results of recompletions.

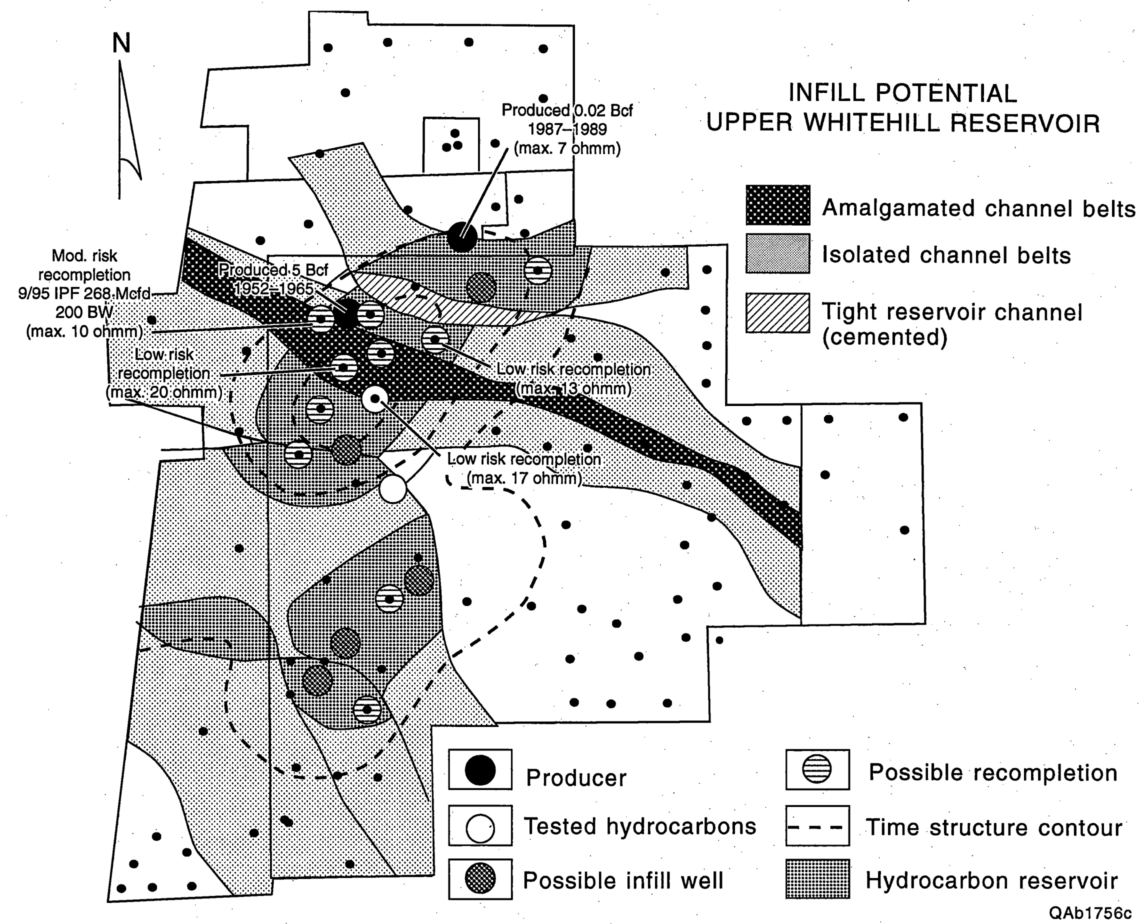


Figure 56. Map showing reservoir compartment distribution, productive limits, identified recompletion/infill opportunities, and results of one recompletion within the upper Whitehill reservoir of T-C-B field. Three recompletion opportunities evaluated as having lower risk than the current recompletion are annotated.

Because of the greater internal heterogeneity within the upper Scott interval, reserve-growth opportunities are more problematic than those in the upper Whitehill. One low- to moderate-risk recompletion exists in Blucher 59, which has excellent resistivity with the top of the reservoir at –5933 ft subsea. Most completions in which the sandstone top occurred above –5940 ft accumulated in excess of 10,000 bo, which would justify the costs of a recompletion. The remainder of the opportunities in the upper Scott include 14 infill well locations. Completions on a spacing as close as 10 acres are justified on the basis of past completion performance, and each

Table 9. Summary of recompletion opportunities in Whitehill reservoir, T-C-B field.

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

should accumulate more than 10,000 bo if they are above –5940 ft. However, such small volumes would not, by themselves, justify the cost of a new wellbore. Creative solutions will be required to produce the large volume of oil remaining in the upper Scott. If other targets can be found in other reservoirs at the infill locations, the economics of a wellbore can be improved. Alternatively, a horizontal well that contacts a larger area, perhaps draining several individual channelforms, might prove economically viable. Without more information regarding the location of individual channelform boundaries, this approach will contain significant technical risk. As mentioned, the Bureau is developing tentative plans to image channelforms using the recently available 3-D seismic data. If the current recovery percentage of less than 10 percent of the original oil in place could be improved, through geologically targeted horizontal drilling, to just 20 percent, more than 0.5 million barrels of reserves could be added.

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

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

Figure 57 illustrates the progression envisioned for the Scott/Whitehill succession of the upper delta plain. Figure 57a represents the upper portion of the sequence underlying the Scott/Whitehill, deposited near maximum relative sea-level highstand and under conditions of high accommodation. Frequent avulsion and meandering create a series of laterally and vertically amalgamated channels within one broad channelbelt.

As sea level begins to fall, resulting in decreasing accommodation, the delta steps seaward, lengthening and straightening the fluvial system and creating a single, potentially incised, channelbelt containing internally homogeneous sandy deposits (Fig. 57b). This is flanked by a broad, slowly aggrading floodplain that receives overbank muds during flood events. This stage corresponds to the deposits of the lower Whitehill, which are dominated by mudstone but may include a single primary channel deposit located outside the study area.

During initial sea-level rise (Fig. 57c), minor accommodation in the upper delta-plain results in infrequent major avulsion events, leading to the deposition of few laterally isolated channelbelts. Within channelbelts, the limited accommodation results in scouring and removal of much of the upper portion of most individual channel deposits. This is similar to the setting of the upper Whitehill reservoir interval and produces reservoir compartments that correspond to channelbelts, laterally isolated but internally homogeneous. As in the upper Whitehill, such reservoirs can be drained effectively by larger well spacings, but infill well locations should be selected so as to avoid the broad areas of floodplain that separate channels. Also, the potential for off-crest stratigraphic accumulations should be considered.

When relative sea level is rising at a maximum rate, the rate of generation of accommodation is also greatest (Fig. 57d). Lateral channel migration and frequent avulsion result in a broad channelbelt composed of many vertically and laterally amalgamated channel deposits. However, because of the preservation of finer grained upper channel and abandoned-channel-fill deposits and the abundance of low-permeability mudclast-rich basal lag deposits, the resulting reservoir deposit will be internally heterogeneous, with many barriers to fluid flow at sandstone-on-sandstone contacts. It should be noted that observations of the Quaternary deposits of the

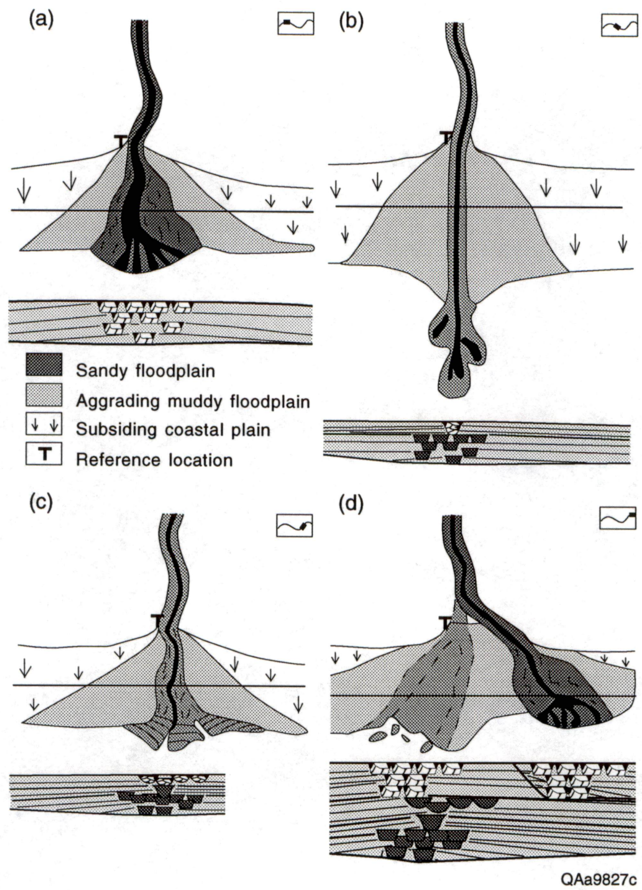


Figure 57. Model for upper delta-plain fluvial architecture under the range of accommodation conditions experienced during a depositional cycle. (a) High accommodation at maximum highstand of relative sea level results in a series of heterolithic vertically and laterally amalgamated channels. (b) Low accommodation during falling relative sea level results in a single internally homogeneous channelbelt. (c) Slightly higher accommodation during initial rise of relative sea level results in occasional avulsion and a series of laterally isolated internally homogeneous channelbelts similar to those in the upper Whitehill. (d) Highest accommodation during maximum rate of rise of relative sea level again results in a single broad heterolithic channelbelt similar to that in the upper Scott reservoir interval. This is also a period during which the fluvial system may be prone to major avulsion and switching of the deltaic depocenter.

Colorado River of Texas (Blum, 1990) suggest that periods of high accommodation may represent times when major avulsion of a fluvial system occurs, resulting in substantial shifting of the locus of deltaic deposition. The upper Scott reservoir was deposited under such conditions of high accommodation. Here, sufficient permeability between individual channel deposits exists to allow the reservoir to have a common oil/water contact because it filled over geologic time.

However, enough permeability barriers or baffles exist that over the period of reservoir depletion, the reservoir responds as though it were composed of a number of isolated compartments.

In summary, a spectrum of reservoir styles exists within the upper delta-plain deposits of the Frio Formation in T-C-B field (Fig. 58). This spectrum is the result of varying amounts of accommodation during the period of deposition of the reservoir sandstones. Reservoirs range from moderately narrow, internally homogeneous channelbelts deposited under conditions of low accommodation in the seaward-stepping portion of a depositional cycle to broad internally heterogeneous channelbelts laid down under conditions of high accommodation in the landward-stepping phase of a depositional cycle. These reservoir styles contain varying reserve-growth potential and require very different strategies for optimum development. In general, upper delta-plain fluvial reservoirs deposited during a landward-stepping period contain the greatest reserve-growth potential and may require the tightest well spacings for optimal reservoir drainage.

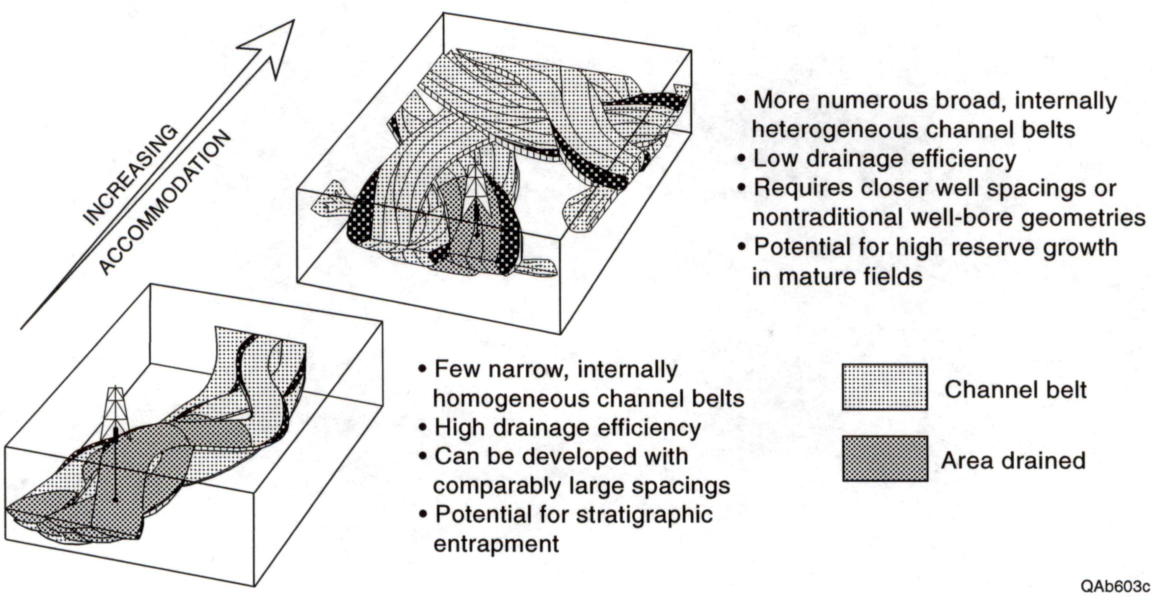


Figure 58. Spectrum of upper delta-plain fluvial reservoir architecture, internal heterogeneity, production characteristics, and reserve-growth potential encountered in the Scott/Whitehill interval.

A Cautionary Note

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

Uses of the Model

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

The model is an integral component of a quick-look analysis of reserve-growth potential. Reservoirs are placed within a framework of depositional cycles to predict internal stratigraphic heterogeneity. Other factors, such as initial estimates of structural heterogeneity, reservoir significance, and past completion history, are integrated. Reservoirs can then be ranked in terms of estimated reserve-growth potential based on this information. Significant reservoirs with sparse completions and high structural or stratigraphic heterogeneity would rank high and receive further attention to refine the estimation of reserve-growth potential. Ultimately, this leads to the informed selection of specific intervals for detailed reservoir characterization aimed at identifying the location of remaining mobile oil or gas.

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

Further Work

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

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

TECHNOLOGY TRANSFER ACTIVITIES

Though technology transfer has occurred throughout Project Years 1 and 2, it became a primary focus during Project Year 3. In addition to the presentation of technical results at conferences, in manuscripts, and in other opportunities that arose, preparations began for two short courses that would attract operators within the Frio Fluvial-Deltaic Sandstone Play and other plays and provide them with sufficient information and motivation to undertake detailed characterization studies in their own reservoirs. The accomplishment of this objective will improve recovery of oil from mature fluvial-deltaic reservoirs and prevent the premature abandonment of fields in the Frio, and other, plays.

Year 3 Technology Transfer

A substantial effort has been made during Year 3 to communicate the methods used in this study, and the results obtained, for the regional assessment of resources and for the integrated multidisciplinary characterization of individual reservoirs to operators of fluvial-deltaic reservoirs. This communication has been carried out through four oral presentations and one poster presentation at major technical meetings (the national meeting of the American Association of Petroleum Geologists and the annual meeting of the Gulf Coast Association of Geological Societies), three publications, and key involvement in two short courses developed through other Bureau projects.

The oral and poster presentations were carefully targeted to reach Gulf Coast operators, as well as a broader national audience. Presentations at the national AAPG meeting (Holtz and

McRae, 1995b; Knox and McRae, 1995; McRae and Holtz, 1995), held in Houston during March, attracted substantial interest and were followed by an invitation to present findings and hold discussions with a major operator within the Frio play. Presentations at the annual GCAGS meeting, held in Baton Rouge during October, received attention from many operators throughout Texas and Louisiana.

Publications included manuscripts in the Transactions volume of the GCAGS meeting expanding on the oral presentations and creating a more complete and permanent record to which interested operators could refer (Knox and McRae, 1995; McRae and Holtz, 1995). In addition, a Topical Report (McRae and others, 1995) focusing on methods and results of the Rincon reservoir characterization studies was accepted and published by DOE.

In addition, much of the regional resource assessment work done during Phase I, and the characterization methodology developed, was the focus of a short course hosted by the Petroleum Technology Transfer Council, discussed below, and was documented in course notes provided to attendees. The accommodation-based model of fluvial-deltaic play architecture used in the T-C-B characterization study was presented to a broad audience in another short course. Details of both short courses are provided in the following sections.

PTTC/TIPRO Workshop

The approach to reservoir characterization that was used in this project, along with results of the resource assessment for the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) Play, was presented to operators of this play during August in Houston as part of a workshop developed jointly by the Bureau of Economic Geology, The University of Texas at Austin; the Petroleum Technology Transfer Council (PTTC), and the Texas Independent Producers and Royalty Owners Association (TIPRO). A total of 29 operators, geologists, engineers, and geophysicists attended.

The presentation was divided into three sections. The first part was an introduction to Texas oil and gas plays and reserve growth concepts. Sources and processes of reserve growth, play analysis, geological play determination, geologic provinces of the Texas Gulf Coast, and depositional systems models were some of the topics outlined in this section. The point was made that the future of activity in this play lies with reserve growth in already discovered reservoirs.

The second section was a slide presentation on Frio Fluvial-Deltaic Sandstone Play characteristics. Topics included an introduction to the play; an in-depth look at its depositional system makeup; and specific petrophysical attributes, fluid characteristics, and volumetrics of the play. Some of the questions asked concerned the use and resolution of 3-D seismic data as an exploration tool for this play.

The third section encompassed reservoir characterization methodology. Four steps were discussed, including determination of reservoir architecture, establishment of fluid flow trends, the integration of both, and identification of reserve growth potential. Specific field examples were incorporated into this portion of the talk with reference to the Rincon field of South Texas.

GRI Ferron Field Trip

The second workshop was developed by the Bureau of Economic Geology, The University of Texas at Austin, and the Gas Research Institute (GRI) to make geologists, engineers, and geophysicists aware of the breakthroughs in prediction of reservoir architecture within a sequence stratigraphic framework. The workshop consisted of a 3-day field trip to examine exposures of the Ferron Sandstone, Utah. In addition to representatives from the BEG and GRI, the trip was attended by 22 geoscientists from large independents, major integrated petroleum companies, and Latin American oil companies.

The initial work that made recent breakthroughs in reservoir architecture prediction possible was a detailed investigation of reservoir architecture, heterogeneity, and detailed petrophysical characteristics of the fluvial-dominated deltaic Ferron Sandstone of central Utah. This study was carried out by the Bureau of Economic Geology and sponsored initially by GRI and later cofunded by an industrial associates group. These concepts were used extensively during the investigation of compartmentalization within the Frio play. Paul Knox presented the results of a study of reservoir architecture in T-C-B field (Knox and McRae, 1995) as an example of the application of concepts developed from the outcrop to subsurface studies. The talk underscored the practical utility of these emerging concepts and was well received.

Short Course Preparations

Two full-day short courses are being planned for early 1996 to communicate directly with operators within the Frio Fluvial-Deltaic Sandstone Play. The South Texas Geological Society in San Antonio and the Houston Geological Society have offered to host these short courses and conduct the necessary advertising and arrangements. The meeting in San Antonio will also be advertised in Corpus Christi, providing us access to the three major cities where operators in the play have offices. Tentative plans are for the course to be offered in San Antonio during early April and during late May in Houston.

The courses will include a review of fluvial/deltaic depositional settings and an overview of the Frio Fluvial-Deltaic Sandstone Play. Methods and results of the playwide resource assessment will be presented, as will a detailed discussion of the integrated multidisciplinary reservoir characterization methodology used in this study. Results of both field studies will then be followed by guidelines for prioritizing reservoirs for detailed study, in order to encourage operators to focus first on those reservoirs most likely to contain substantial reserve-growth potential. Frio core from Rincon field will be available for viewing during breaks, and a brief demonstration of a pre-release version of the geologic reservoir characterization advisor will be given. The presentations throughout the day will be interspersed with brief but informative exercises to demonstrate the points being presented. Lunch will be provided as part of the registration cost, which will be kept low to attract small operators as well as large.

Preparations have begun on a set of course notes that will be provided to attendees. The course notes will include copies of important illustrations used during presentations, materials for exercises, and copies of relevant publications.

GEOLOGIC RESERVOIR CHARACTERIZATION ADVISOR

Introduction

In an effort to make the results of this study available to operators on a day-to-day basis, and in a form that is most useful and flexible, we will incorporate methods and results into a microcomputer-based software package referred to as the Geologic Reservoir Characterization Advisor (GRCA). To improve its appeal, the GRCA will be designed to be user-friendly and compatible with nearly any computer in use by operators within the Frio Fluvial-Deltaic Sandstone Play.

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

Software Development

The GRCA demonstrates the planning process and strategies employed in the real world when characterizing reservoirs to identify reserve growth potential and is based on actual Bureau research strategies developed over the last 15 years. The intended user audience is the independent oil exploration company, which may not be able to afford the services of a consulting geology firm.

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

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

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

The GRCA will serve as a complete tutorial package, allowing users to work at their own pace. Users may choose to stop at any point and come back later to the same point in the tutorial or to review material already presented. Although it is beyond the scope of the Advisor to simulate reservoir models completely, basic analysis procedures will be presented so that the user can grasp the general idea. These procedures will be first shown to the user with sample data developed by Bureau content experts, then, optionally, with data the user may already have at hand. When the user is prompted to enter real-world data to work through certain procedures, that data will be stored as a sort of workbook for recall and use in later procedures as appropriate. The workbook can then be printed at the completion of the tutorial for a permanent record of the user's work.

PLANNED ACTIVITIES

Completion of Phase III Activities

Phase III tasks 4 and 5, Technology Transfer and the Geologic Reservoir Characterization Advisor, respectively, will be completed during the fourth and final project year. Technical presentations and publications will continue to communicate with a wide audience regarding methods and final results of field studies, as well as to introduce and explain the GRCA. The two short courses planned will reach a more focused group of operators within the play. The portability of results from the Frio Fluvial-Deltaic Sandstone Play (Vicksburg Fault Zone) to other fluvial/deltaic plays will be evaluated and communicated to operators to help them evaluate the applicability of results to fields in other plays. Finally, because confirmation of project results is an important validation of the methodologies used, we will continue to support the operators at Rincon and T-C-B field as necessary to bring identified opportunities to fruition.

Technology Transfer

Several presentations at technical meetings are planned for 1996. In fact, authors of a paper discussing the applicability of accommodation-based models to reservoir characterization have been invited to present the paper at the 1996 national AAPG meeting, to be held in San Diego during May, and another paper covering Rincon field results has been submitted. In addition, we anticipate submitting abstracts to the 1996 GCAGS meeting, to be held in San Antonio in October, addressing final results of field studies and a description of the GRCA. If accepted for presentation, the GCAGS abstracts will be accompanied by manuscripts. In addition, a Final Report documenting activity in all phases of the project will be submitted to DOE at project completion on August 31, 1996.

As mentioned above, two short courses are also being prepared for operators within the Frio Fluvial-Deltaic Sandstone Play. These are considered a primary goal of the Technology Transfer effort. Much of the remainder of 1995 and early 1996 will be spent preparing presentations, exercises, and a notebook containing course notes for these events. Planning for logistics has already begun and dates are being investigated.

The Geologic Reservoir Characterization Advisor

The final task of the project will be the completion and distribution of the GRCA. Programming on a test version has begun, and we anticipate having a pre-release version available for demonstration at the short courses in early 1996. Release is scheduled for June 1996. The GRCA will be advertised in the flyers announcing the short courses, targeting an audience consisting primarily of operators within the play.

CONTINUED OPERATOR SUPPORT, RINCON AND T-C-B FIELDS

An unscheduled task of variable activity level during the final project year will be the continued communication with, and support of, operators in Rincon and T-C-B fields. Although recommendations for specific reserve-growth opportunities have been made, our continued interest and support will increase the probability that the operator will act on those recommendations. This serves the interests of DOE by improving the chances of measurable increases in production and reserves from fluvial-deltaic reservoirs and validates the approach of integrated multidisciplinary reservoir characterization.

The range of support necessary cannot be predicted at this time. It may range from supplying operators with additional copies of maps for presentation to decisionmakers up to conducting detailed stratigraphic interpretation of a 3-D seismic dataset to image heterogeneity within major fluvial channelbelts, in support of horizontal development wells. The worklevel will be balanced against ongoing technology transfer activities to optimize the impact and credibility of project results.

ACKNOWLEDGMENTS

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APPENDIX: 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: Gulf Coast Association of Geological Societies Transactions, v. 44, p. 487–498.

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

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

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. 227, 46 p.

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

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

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

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