SECONDARY NATURAL GAS RECOVERY: TARGETED TECHNOLOGY APPLICATIONS FOR INFIELD RESERVE GROWTH

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Activities during the year comprised screening and selection of gas fields for detailed studies; integrated geological, petrophysical, geophysical, and engineering analyses of the fields selected; and data acquisition in cooperative wells. A comprehensive work-plan was prepared, and a methodology for geological and engineering screening of sandstone reservoirs was developed and applied to leading candidate fields. Contacts made with field operators resulted in active participation of Mobil Exploration and Producing U.S., Inc., and Shell Western Exploration and Production Inc. Lake Creek, Seeligson, McAllen Ranch, and Stratton-Agua Dulce fields were selected for study. These fields are representative of a spectrum of depositional systems and reservoir heterogeneities in highly productive gas reservoirs in the Texas coastal plain. Producing intervals are fluvial Frio reservoirs in Seeligson and Stratton-Agua Dulce fields, deltaic Vicksburg reservoirs in McAllen Ranch field, and deltaic Wilcox reservoirs in Lake Creek field. New data, comprising cores, open- and cased-hole logs, vertical seismic profiles, and sequential formation-pressure tests, were acquired in two wells in Seeligson field and in one well in McAllen Ranch field. Results to date suggest that reservoir heterogeneity can be defined using integrated geologic, geophysical, and engineering data.

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RESEARCH SUMMARY

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Objectives

The objective of this project is to better enable natural gas producers to economically define and develop unrecovered natural gas within known conventional fields. Project assessment of incremental natural gas recovery from these fields is dependent on technical innovations for development of bypassed reservoirs, compartmentalized reservoirs, and, to a lesser extent, deeper-pool reservoirs. The resource amenable to this type of extended conventional development has been estimated at 119 Tcf in the Lower 48 states by the U.S. Department of Energy in a 1988 report.

Technical Perspective

Reserve growth from existing reservoirs is a major source of oil reserve additions. Therefore, it is appropriate to determine any similar potential for incremental natural gas recovery using new approaches to reservoir characterization. These approaches must include the integration of geology, geophysics, reservoir engineering, and petrophysics/formation evaluation for maximum effectiveness.

In the last 10 years, characterization of the internal geometry of reservoirs, mainly oil reservoirs, has uncovered a higher degree of compartmentalization than was previously recognized. This compartmentalization is primarily a function of the depositional system and, secondarily, of the structural and diagenetic history of the reservoir after deposition. Where significant geologic variation occurs, untapped or bypassed reservoir compartments remain to be drained of natural gas by drilling or recompleting strategically placed development wells. Deeper-pool potential, which is closely related to depositional systems, can be better defined by sequence stratigraphy and borehole seismic methods and also offers opportunities for increased reserves.

Results

A comprehensive workplan of integrated geological, petrophysical, geophysical, and engineering studies was developed. A computerized data-base system was acquired to manage the extensive and diverse information used in the interdisciplinary studies. Among leading candidate Southeast, South-Central, and South Texas gas fields, Lake Creek, Seeligson, Stratton-Agua Dulce, and McAllen Ranch fields were selected for reservoir heterogeneity and data acquisition studies in cooperative wells. The fields were selected by applying a methodology developed by the project for the geological and engineering screening of sandstone reservoirs. Producing intervals are fluvial reservoirs in the Frio Formation (in Seeligson and Stratton-Agua Dulce fields) and deltaic reservoirs in the Wilcox (in Lake Creek field) and in the Vicksburg (in McAllen Ranch field).

Data-acquisition programs for Seeligson, McAllen Ranch, and Lake Creek fields were prepared with the cooperation of the field operators. The data acquired would help characterize reservoir heterogeneities in the interwell areas. Sidewall cores, open- and cased-hole logs, vertical seismic profiles (VSP), and formation-pressure data were collected in two deeper-pool tests drilled by Mobil Exploration and Producing U.S., Inc., in Seeligson field. At the end of the research year, acquisition of new data (cores, vertical seismic profiles, and formation-pressure tests) were in progress in one well that was being drilled by Shell Western Exploration and Production in McAllen Ranch field.

Additional data collection is planned for Seeligson and Lake Creek fields. A zero-offset vertical seismic profile is programmed in a well that Mobil plans to deepen in Lake Creek field in 1989. Further data acquisition in Frio reservoirs in Seeligson field has been proposed to Oryx Energy Company. The program consists of vertical seismic profiles, cross-borehole tomography, pressure-interference tests, and cased-hole logs.

Project results to date indicate that reservoir heterogeneity in the interwell areas can be defined using geologic and geophysical techniques. Newly acquired data confirm the results obtained during field screening. Initial results indicate reservoir compartmentalization in the fields selected. Geological data indicate mostly laterally discontinuous sandstones, and engineering data suggest that some of the reservoirs are compartmentalized. Further, initial processing of VSP data from Seeligson field suggests complex lateral stratigraphic relations of fluvial sandstones, as indicated by variations in frequency, polarity, and the occurrence of reflector terminations. This suggests, therefore, that reservoir heterogeneity in the interwell areas can be defined geophysically. Reservoir heterogeneity and potential for untapped gas reserves are highest in fluvial reservoirs having a multistory, vertically stacked facies architecture, such as in Stratton field.

Technical Approach

Screening of heterogeneous fluvial-deltaic reservoirs of South Texas defined the first areas of field data collection and formed a major part of early project activities. Geologic and engineering analyses of publicly available and industry-supplied data helped define natural gas fields potentially suitable for analysis. Obtained results formed the basis for presentations to industry on the benefits of cooperating in the Secondary Gas Recovery program and led to cooperative field studies at Seeligson field (Frio Formation) with Mobil Exploration and Producing U.S., Inc., during the report period. An agreement signed with Shell Western Exploration and Production, Inc., covering a cooperative well in McAllen Ranch field (Vicksburg Formation), will lead to extensive field activities early in the next report period, as will proposals made to Oryx Energy for continued work in Seeligson field.

Project Implications

The report describes results to date of field screening; acquisition of new data; and integrated geological, geophysical, and engineering investigations in gas fields producing from terrigenous clastic reservoirs in South Texas. The research will help guide gas reserve growth by delineating untapped and partly drained reservoir compartments using state-of-the-art and emerging technologies. The first year of studies has addressed reservoir heterogeneity in several types of reservoirs, thereby setting the stage for more detailed analyses. Continuing studies will include collecting additional data in cooperative wells, drilling a Staged Field Experiment (SFE) well, and initiating studies of carbonate reservoirs in 1990. The cooperative and SFE wells will provide an excellent opportunity to test technologies such as cross-well seismic imaging currently under development by GRI. Part of the research (that on Lake Creek field) complements GRI's basic research studies on reservoir characterization.

CONTENTS

Figures

Tables

INTRODUCTION

This report summarizes activities conducted during the first year of the Secondary Gas Recovery (SGR) project for which the Bureau of Economic Geology (BEG) serves as Lead Technical Contractor. Investigations began in September 1988, funded by the Gas Research Institute, the U.S. Department of Energy, and the State of Texas. Objectives of the project, defined in the research proposal "Secondary Gas Recovery: Targeted Technology Applications for Infield Reserve Growth," are development and testing of methods to determine the distribution of unrecovered gas resources by depositional system and to maximize ultimate recovery of these resources. Research targets are gas accumulations that lie in stratigraphically controlled, untapped, and partly drained reservoir compartments and in closely related deeper pools (fig. 1).

The project consists of interdisciplinary investigations. Research results will better enable gas producers to define reexploration, extended development, and reservoir management strategies using integrated geological, geophysical, petrophysical, and engineering assessments. The project is field oriented. Close cooperation of operating companies is essential for project data collection and testing of hypotheses in cooperative wells located in the areas selected for detailed studies. Geological and engineering hypotheses and field techniques will be tested in a Staged-Field-Experiment (SFE) well that will be drilled and that will form part of the SGR research program. Final analysis involves assessment of the fieldwide and playwide extrapolation potential of the research results.

Research activities during the first year of the project focused on Tertiary fluvial and deltaic sandstone reservoirs in the onshore Gulf Basin, especially South-Central and South Texas. Some of these reservoirs grade laterally into less heterogeneous barrier-bar/strandplain systems. Previous depositional systems studies indicate that these reservoirs are stratigraphically heterogeneous and therefore have good potential for unrecovered gas reserves

RESEARCH TARGETS

Study Scales	Bypassed Gas	Untapped Compartments	Deeper Pools
Pore Throat	Cores Logs	Cores Logs	———
Facies	Cores Logs - include PML Single - well pressure testing Borehole gravity survey	Logs Multi - well pressure testing VSP	———
Reservoir	Logs - including PML Borehole gravity survey	Logs Multi - well pressure testing Borehole gravity Cross-hole tomography 3-D seismic, VSP Geochemistry Horizontal stratigraphic test	3-D geologic modeling
Field	Synthesis and extrapolation	Logs Borehole gravity 3-D seismic, VSP 3-D geologic modeling	3-D geologic models Regional seismic Regional log data
Play	———	Synthesis and extrapolation	Regional seismic Sequence and systems analysis Geochemistry Regional log data
Basin	———	———	Regional seismic Sequence and systems analysis Regional paleo Geochemistry Regional log data

Figure 1. Research targets, Secondary Gas Recovery: Targeted Technology Applications for Infield Reserve Growth project.

lying in intrareservoir traps. Research conducted during the year comprises (1) selection and implementation of a computerized data-base system, (2) screening of gas fields, (3) initial formation evaluation, geological, and reservoir modeling investigations in selected fields, and (4) infield data-acquisition programs.

The project staff established contacts among companies that had relatively high levels of drilling and completion activities in the area of study during 1988 and early 1989. These discussions resulted in the release of field operators' proprietary information and the acquisition of new infield data by the project.

Activities were carried out by four SGR task groups. Geological studies were by the BEG. ResTech of Houston, Texas, conducted well log analysis and formation evaluation studies and coordinated digitization of well logs for input in a computerized data base. Research and Engineering Consultants (REC), of Englewood, Colorado, undertook engineering and reservoir-modeling investigations. Envirocorp (formerly Ken E. Davis and Associates) of Houston, Texas, monitored drilling and completion activities in the South Texas Frio play and coordinated data-acquisition operations in cooperative wells. The BEG directed and coordinated all SGR activities.

IMPLEMENTATION OF A COMPUTERIZED DATA BASE

The project acquired a computerized data-base system in order to manage the large quantities of diverse data types used in integrated geological, engineering, and well log analysis. The system facilitates communication and transfer of data among the task groups. It also provides utilities that either support analysis directly or export data files to other computation facilities for further analysis.

BEG and REC investigated commercially available software for production geology and engineering studies. Search activities included (1) analysis of vendors' specification literature, (2) demonstrations to SGR staff, and (3) solicited opinions from other systems users regarding each of the products investigated. The analysis resulted in the recommendation to acquire the Reservoir Characterization System II (RCS-II) software from Electronic Data Resources, Inc. (now Zycor, Inc.), of Austin, Texas. Identical versions of the system were installed at BEG and REC facilities. In addition, a Bernoulli input device was installed at ResTech for transfer of well log traces.

The RCS-II data base incorporates and catalogs reservoir and well data by depth, reservoir name, and geographic well location directly from the keyboard or from structured, externally generated files and catalogs the information. Map information is input through a digitizing pad and mapping subroutine. The data can be viewed on the workstation monitor or output to print/plot devices. Output includes maps, well log cross sections, and production or engineering crossplots. In addition, RCS-II interfaces with CPS/PC, a contour-mapping software developed by Radian Corporation of Austin, Texas. Interactive communications between SGR task groups is also achieved with a modem and public phone lines through the use of Carbon Copy software.

The RCS-II system workstation at BEG consists of an AST-386 computer that has an NEC Multisync color monitor. The computer has a 150-megabyte hard disk partitioned into five drives. The monitor is capable of several graphic display modes (for example, CGA, EGA, and VGA). Input to and output from the workstation is performed using a 5-1/4-inch high-density floppy drive and a 5-1/4-inch Bernoulli drive for data transfer between the task groups. Map data are input using a CALCOMP 9100, 24 × 36-inch digitizer. Plots and printouts are output to a Hewlitt Packard Laserjet Series II printer and a Hewlitt Packard DraftPro Multi-Color Pen Plotter. The workstation is connected via an RS232 communication line to a VAX computer. A 1200-baud modem allows direct linkage to computer facilities in REC offices. System usage has increased during the first project year as areas of field studies became better defined and data were acquired from operators.

FIELD SCREENING AND SELECTION OF CANDIDATE FIELDS

Initial project activities focused on the identification of gas fields that have good potential for unrecovered gas resources and that are therefore candidates for detailed studies. Initial screening of fields in the Southeast, South-Central, and South Texas coastal plain resulted in the identification of 14 fields as candidates for further analysis. Four of these fields were selected for detailed investigations and are candidates for project data acquisition in cooperative and SFE wells and potentially in SFE wells.

Screening Criteria

Field screening was undertaken using public information and commercially available well log and production data. A set of screening criteria was established for field selection (table 1), the level of recent drilling and completion activities being one of the initial criteria. Intensity of these activities reflects current trends in reservoir reexploration and extended development and therefore highlights fields having potential for implementation of cooperative research with industry. Other screening criteria deal with the geology, development history, and reserve-growth potential of the fields. In addition, possible operator cooperation and commonality of field ownership were considered.

Geological criteria include structure and stratigraphy. Structurally simple fields are preferred so that the project can discretely focus on depositional reservoir heterogeneity. Similarly, fields that produce from reservoirs forming part of fluvial and deltaic depositional systems are ranked high because the depositional environments of these reservoirs are favorable for reservoir compartmentalization.

Fields having numerous wellbores but relatively wide completion spacing are excellent candidates for the project because they have good possibilities for the identification of bypassed and untapped reservoir compartments. The history of injection operations (water,

Table 1. Criteria used in field screening.

Parameter	Preferred occurrence
Geologic setting	Fluvial depositional systems, deltaic depositional systems, simple structure.
Field-development history	Numerous wellbores, wide completion spacing, good data quality and quantity, ownership commonality.
Reserve-growth potential	Expectation for uncontacted and partly drained compartments, possibilities for infill drilling, possibilities for well recompletions.
Operator cooperation	Open and timely participation in project.

gas recycling) and completion and stimulation practices are important for the project because they affect the occurrence and volume of unrecovered gas resources and the feasibility of extended field development for additional gas recovery. Data availability and quality are essential for the success of the project. Thus, fields having extensive geological, petrophysical, geophysical, production, and engineering data bases are excellent candidates for the project. Furthermore, fields or large parts of a field having one or a few operators are convenient for the project. Commonality of field ownership facilitates project acquisition of existing company data and new data.

A fundamental screening consideration is the existence of possibilities for infield reserve growth, which is the main objective of the project. Fields or parts of fields having ample opportunities for geologically targeted well recompletions and infill drilling are most attractive to the project. Therefore, fields favorable to the SGR project are those that produce from stratigraphically heterogeneous reservoirs that possibly contain unrecovered gas reserves and that are representative of a larger group of reservoirs to which project research results can be extrapolated. Also of particular importance is the potential for cooperation by the field operators. Operator participation in SGR studies is essential for the timely release of existing proprietary well and field data and for optimizing the planning and acquisition of new data in project cooperative and SFE wells.

Biweekly Activity Reports

Drilling and completion activities in gas fields in the South and South-Central Texas coastal plain, the primary area of project focus, were monitored. Using mainly Petroleum Information (PI) weekly reports, Envirocorp prepared 25 biweekly reports highlighting those operators who are most active in the Frio play and the geographic areas of greatest activity. The reports were distributed to the task groups in the SGR project. Good production tests and relatively high reservoir pressures in infill and step-out wells were used in the identification of plays and fields showing good potential for unrecovered gas resources in partly drained and untapped reservoir compartments.

Geological and Production Field Summaries

Geological and production summaries were prepared for 14 natural gas fields in Southeast, South-Central, and South Texas (fig. 2, table 2). Summaries of key data in each field (compiled from public and commercial sources) are presented in Appendix A. High levels of completion and drilling activities in 1988 and early 1989 were one of the criteria used to select the fields summarized. Data were also compiled for some fields lacking recent drilling activities (for example, Lissie) to develop a more complete coverage of depositional systems and reservoir types. The gas fields summarized are part of major gas plays, mostly South and South-Central Texas (fig. 3, Appendix A), and illustrate variations in stratigraphically controlled reservoir heterogeneity and resulting recovery efficiencies in the area.

Reservoir Analysis Techniques for Field Screening

Screening Techniques for Compartmentalization

Preliminary review of production data to identify potentially compartmentalized reservoirs called for the development of new techniques. Two major factors constrained the selection of these techniques: (1) reported shut-in pressures are often not representative of true long-term static pressures and hence were deemed unusable and (2) the designed techniques must be efficient enough that a large number of wells could be reviewed quickly. REC developed two techniques to provide a "quick look" at production characteristics of a field that meet these criteria. The techniques were initially applied to the Stratton and McAllen Ranch fields.

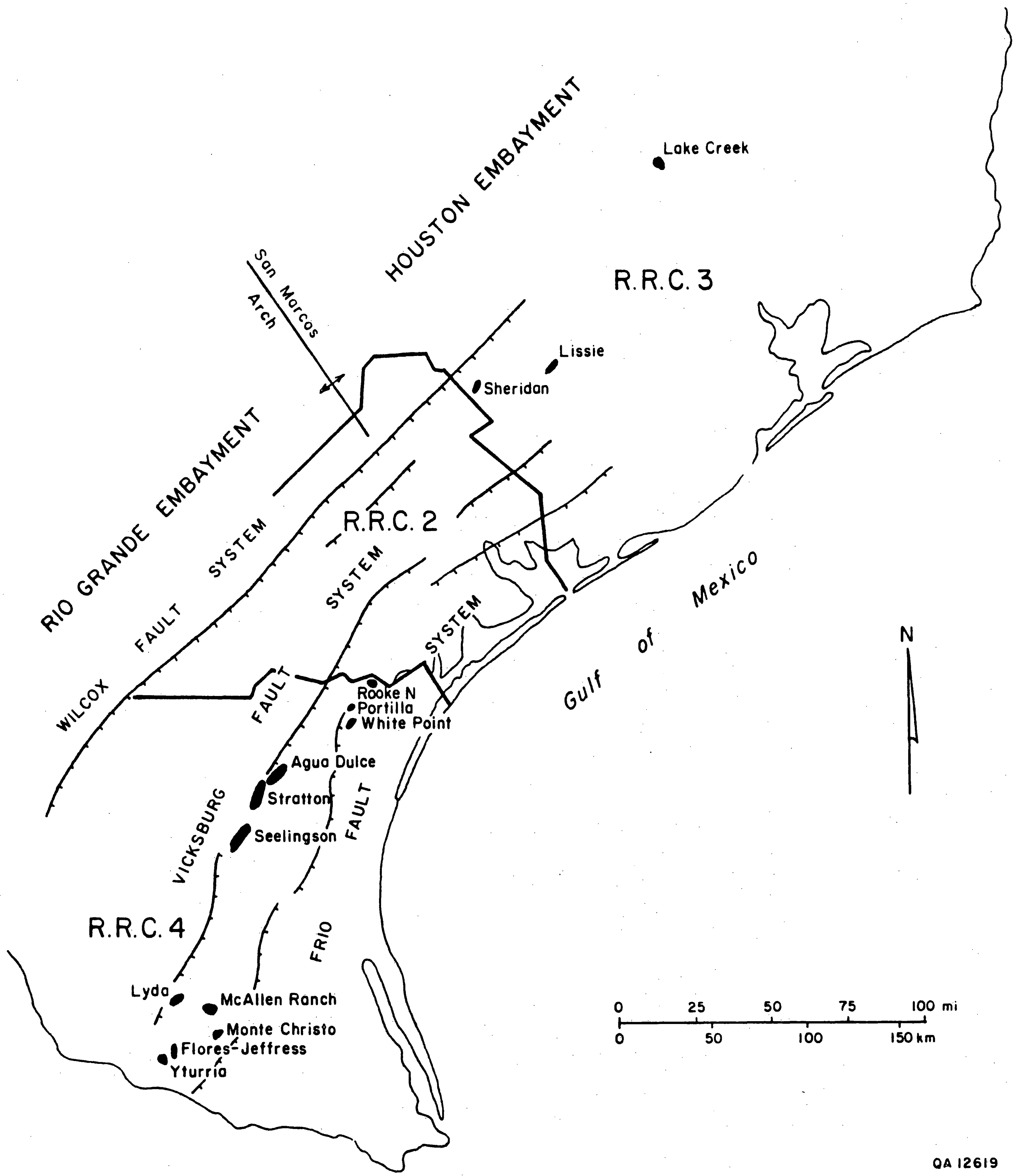

Figure 2. Index map of major tectonic elements, gas fields summarized, and RRC districts in Southeast, South-Central, and South Texas coastal plain.

Table 2. Fields for which geologic and production data were summarized.

Field name (County)	Reservoirs (Plays)	Depositional System
Lake Creek (Montgomery)	Wilcox (WX-1)	Fluvial, deltaic
Lissie (Wharton)	Wilcox (WX-1) Yegua (EO-3) Miocene (MC-3)	Fluvial, deltaic Deltaic Fluvial
Sheridan (Colorado)	Wilcox (WX-1) Yegua (EO-3)	Fluvial, deltaic Deltaic
Rooke (San Patricio)	Frio (FR-7)	Barrier-bar/strandplain
Portilla (San Patricio)	Frio (FR-7) Miocene (MC-1)	Barrier-bar/strandplain Deltaic
White Point East (San Patricio)	Miocene (MC-1) Frio (FR-6)	Deltaic Barrier-bar/strandplain
Stratton/Agua Dulce (Jim Wells, Kleberg, Nueces)	Frio (FR-4) Vicksburg (VK-1)	Fluvial Deltaic
McAllen Ranch (Hidalgo)	Vicksburg (VK-1)	Deltaic
Flores/Jeffress (Starr, Hidalgo)	Frio (FR-4) Vicksburg (VK-1)	Fluvial Deltaic
Monte Christo (Hidalgo)	Frio (FR-4) Vicksburg (VK-1)	Deltaic Deltaic
Yturria (Starr)	Frio (Fr-4) Vicksburg (VK-1)	Fluvial Deltaic
Lyda (Starr)	Vicksburg (VK-1)	Deltaic

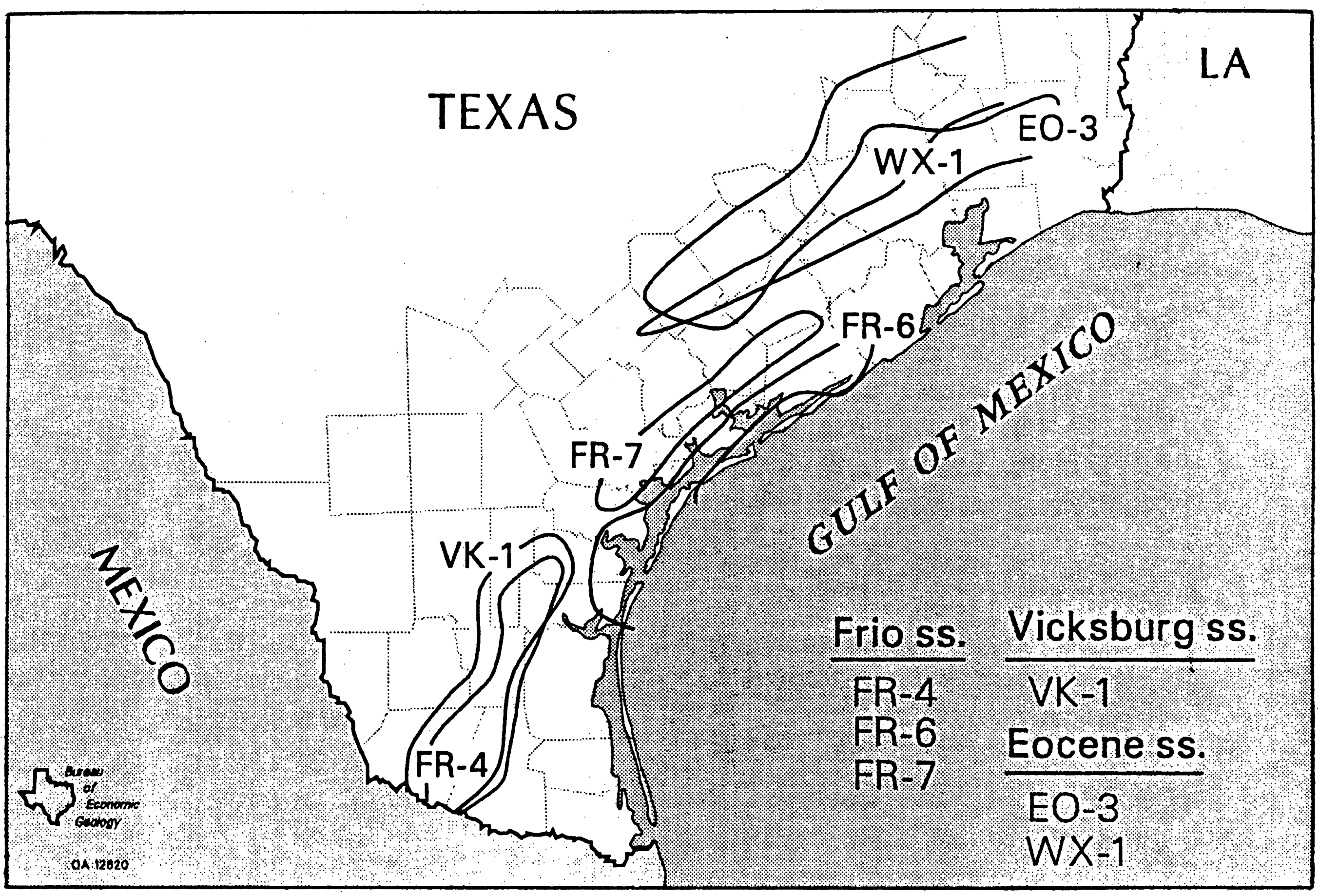

Figure 3. Index map of gas plays containing fields summarized, Texas coastal plain.

Q-ratio plot. One screening technique uses the fact that the rate of decline for production of a well is essentially inversely proportional to the reservoir volume drained by the well. Specifically, for a well exhibiting exponential decline it can be shown that the decline rate parameter, "a," is given approximately by

$$a \approx \frac{Q_1}{Q} \approx \frac{q_o - q_1}{q_o}$$

where q_o is the initial flow rate, q_1 and Q_1 are the flow rate and cumulative production after one year, respectively, and Q is the cumulative production over a long period of time. Then a is defined as the fractional decline in production rate per year.

For any exponential decline scenario, type curves may be generated as illustrated in figure 4. Each will possess its own characteristic shape. Further, the decline rates need not remain fixed for the life of the well. A sort of "pseudo"-hyperbolic decline may be constructed consisting of an average decline rate of 50 percent per year for the first year, 40 percent per year for the second year, and so on until a final, shallow decline rate, say 10 percent per year, is maintained for the remaining life of the well. In the case of a variable decline rate, the curve will approach an asymptote corresponding to a constant decline rate somewhere between the initial and final decline rates.

Once the type curves have been generated, well data may be posted to see what sort of decline character each well is displaying. If a point falls much closer to the 10-percent-per-year curve than to the 50-percent-per-year curve, the well probably has a relatively slow decline rate. Conversely, a point falling on or near the 50-percent curve indicates a much steeper decline and more rapid deterioration of the initial rate.

Two important points about the technique must be stressed: (1) the technique allows comparisons of decline character among a group of wells based solely on cumulative production to date and original rate (that is, only one data point on the decline curve of each well), and

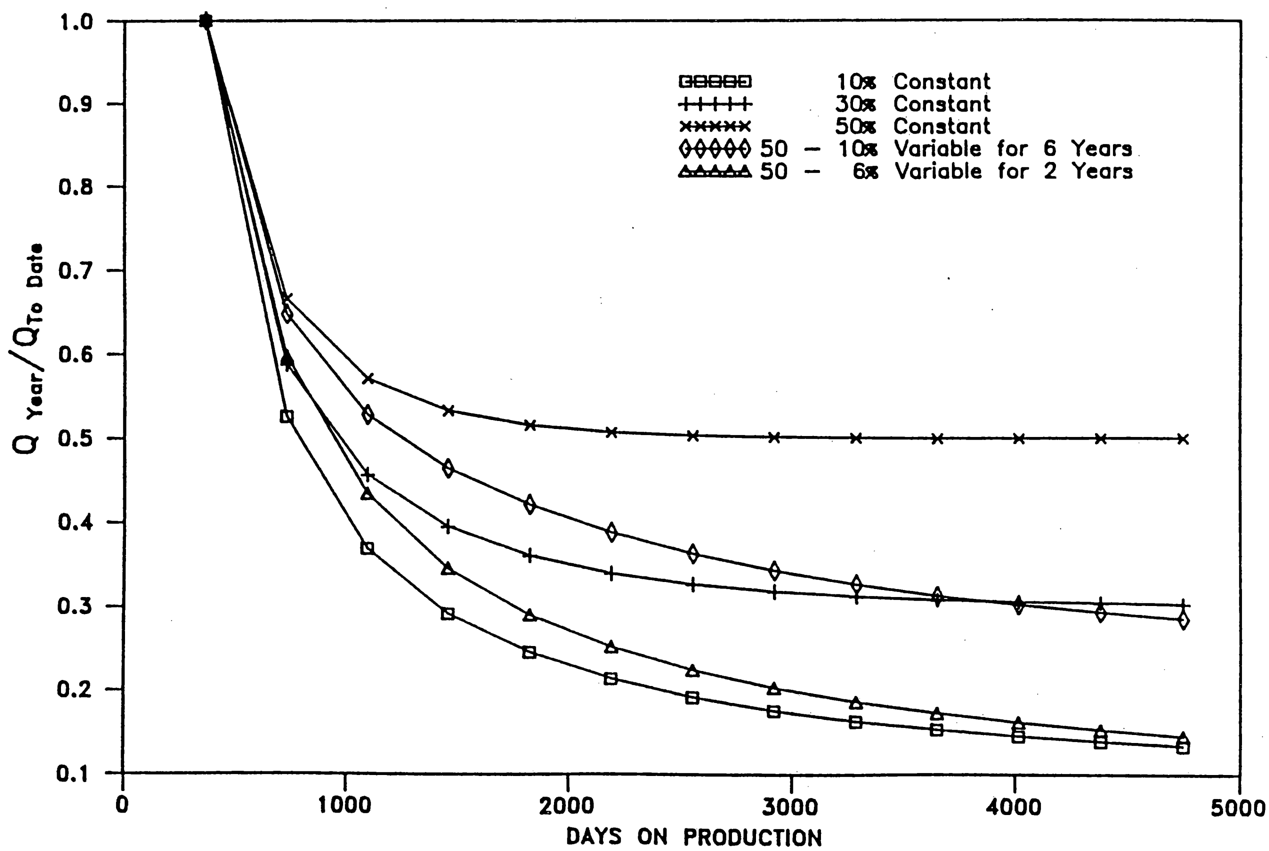

Figure 4. Q-ratio type curves for various decline scenarios.

(2) the technique is most applicable to wells of widely different decline character. Thus, this technique is most appropriate for a "quick look" at decline performance in a field. For more complete analysis, the entire decline curve of each well should be used.

Initial-rate plots. The second plot incorporates the actual well production rate into the analysis. Whereas the previous method made no explicit use of rate, the production rate history is important as a diagnostic tool. Naturally, it is economically desirable for wells to be as prolific as possible; a small decline is meaningless if the initial production rate is noncommercial. Additionally, initial trends in variation of rates with time can provide valuable insight into the characteristics of a reservoir.

Some estimate of an initial potential must be made for each well because a preliminary screening study would not involve analyzing the complete production history for any well. For reasons to be detailed in future technical reports, inaccuracies in analyzing four-point back pressure tests typically render useless the absolute open flow (AOF) values reported by operators. In addition, the first month of production cannot be used because usually the production is for only part of the month. The daily average of the entire production for the first year was therefore used as an estimate of initial potential for a well. In this manner the seasonal effects of market conditions and curtailments can also be accounted for in all cases.

The procedure for the Initial-rate plot was to graph the daily average rate for the first 12 months of production versus the completion date. When done for all of the wells completed within a given horizon, the trend of initial well productivity with age of the field can be illustrated.

Q-ratio and Initial-rate plots as screening tools. The use of the two techniques described above is best illustrated graphically for two idealized reservoirs. These methods are screening techniques for detecting potential reservoir compartmentalization, and we are looking for trends in the field data.

Consider first an ideal "blanket" reservoir. All parts of the reservoir are relatively homogeneous, continuous, and in pressure communication. Figure 5 illustrates the trends that

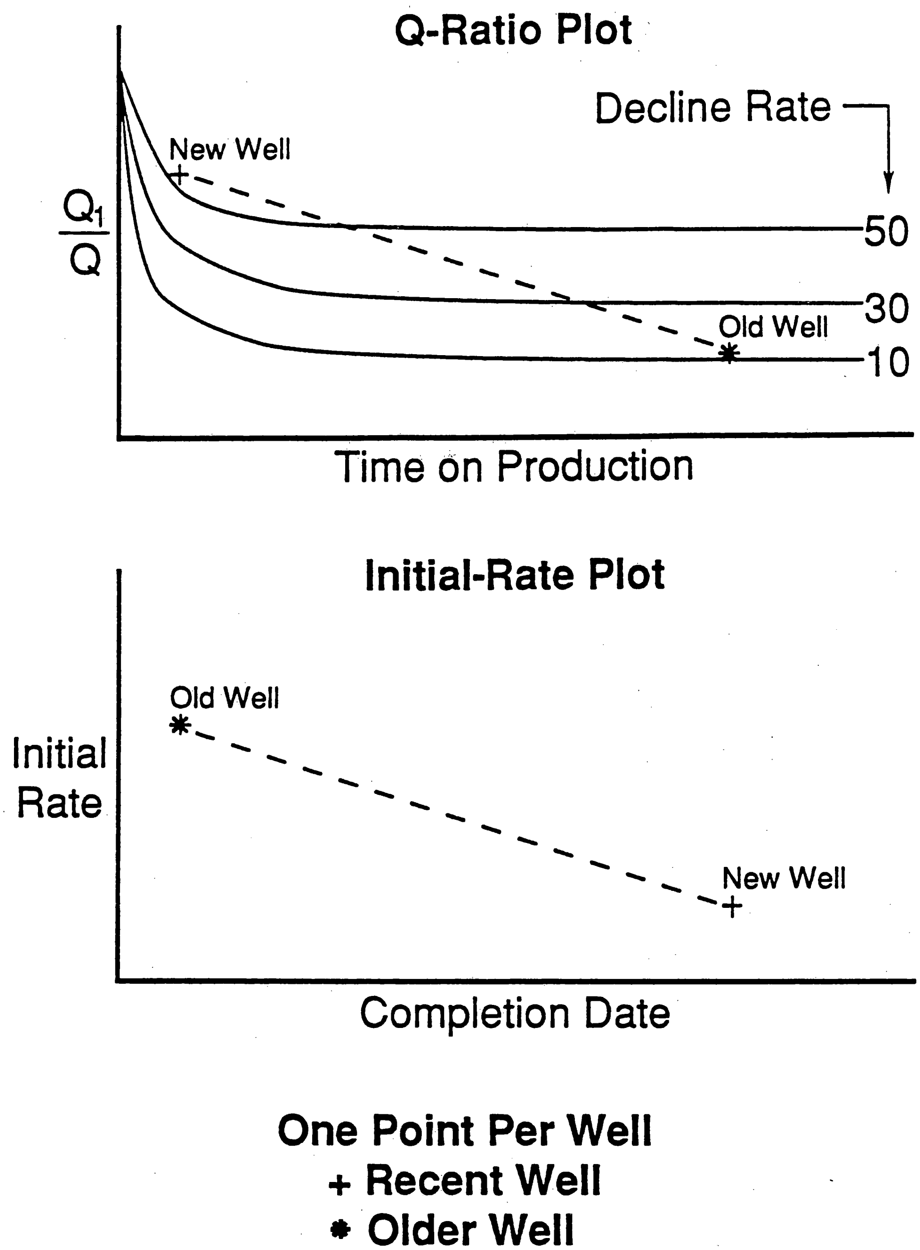

Figure 5. Q-ratio and Initial-rate curves of a blanket sand reservoir for various decline scenarios.

the field data are expected to exhibit in this case. Since the decline rate is primarily a function of drainage volume, the characteristic decline rate for the wells in the field gradually increases with a decreasing production life. This is because in a blanket sand each new well drilled effectively reduces the drainage area of all the wells in the reservoir. Such a trend is illustrated in the Q-ratio plot. The Initial-rate plot for the same sand shows a trend of initial potential decreasing with the life of the field. Initial rate of a well is largely dependent upon the initial reservoir pressure. In a reservoir where all areas are in pressure communication, the pressure will decrease as gas is produced. Thus, one would expect a general decrease in initial potentials with time.

A second ideal reservoir is that of a completely compartmentalized sand. Each new well drilled encounters an undrilled compartment at virgin pressure, and all compartments are essentially the same volume. Figure 6 shows the expected trends in this case. Because each new well tests a new compartment at the same pressure and of the same volume, there is essentially no change in decline character or initial rate with field age.

"Blanket" and compartmentalized reservoirs (figs. 5, 6) are ideal scenarios. However, as was demonstrated in preliminary studies of the Stratton and McAllen Ranch fields (discussed in the section "Initial studies of selected gas fields," p. 19), these trends are often approximated in actual situations. Thus, as an engineering screening method, this approach defines reservoirs that should be evaluated further.

Four-Point Test Data

When a gas well is completed, a deliverability test is run that involves measuring flow rates, flowing pressures, shut-in times, and shut-in pressures. A variety of different tests may be run. However, the one required by the state of Texas and that which is reported by all operators on standard well completion cards is the conventional four-point back pressure test. The procedure for running the test is relatively straightforward. The well must first be shut-in

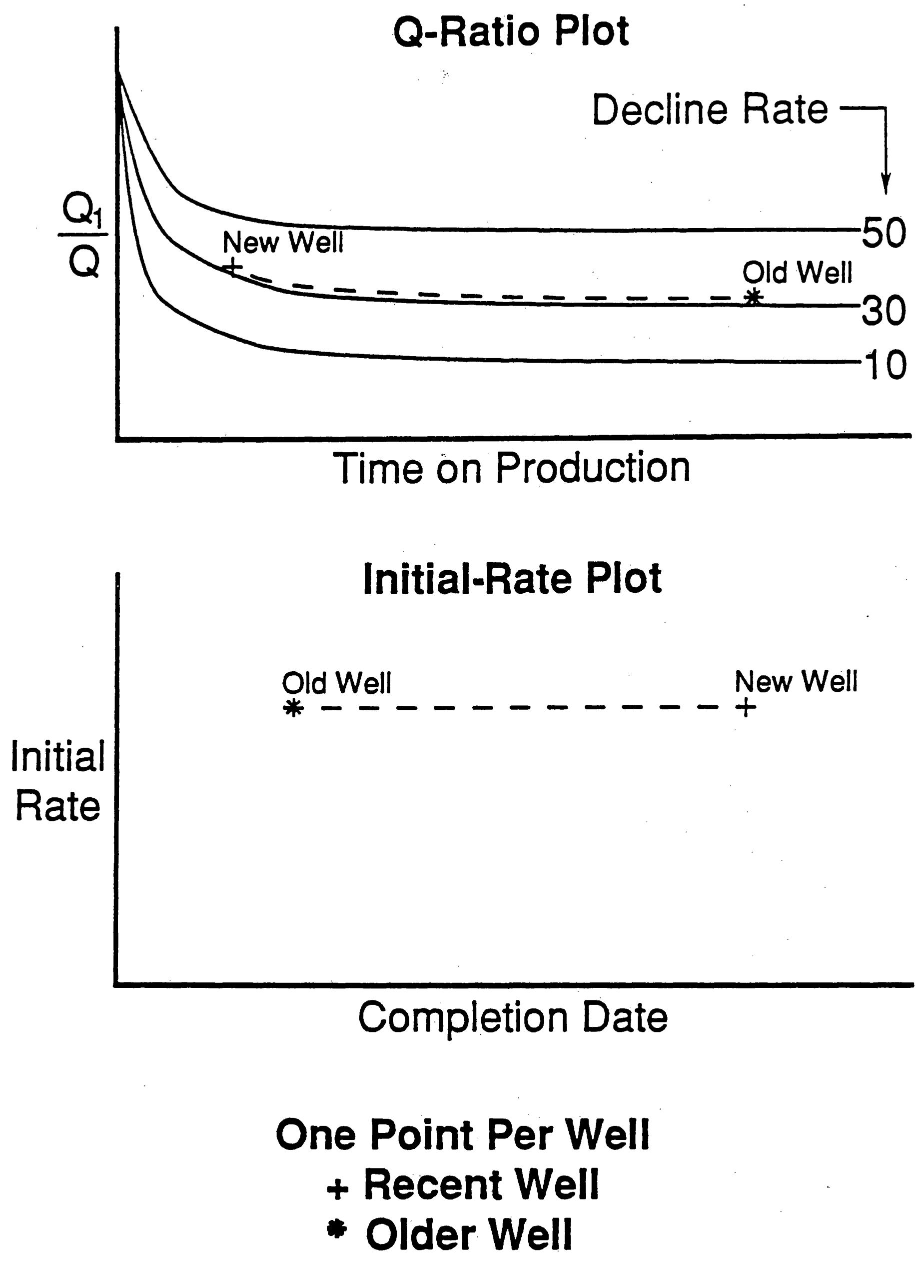

Figure 6. Q-ratio and Initial-rate curves of a compartmentalized sand reservoir for various decline scenarios.

for a sufficient period of time to allow buildup to maximum pressure. The well is then opened to flow and production proceeds at a constant rate until the flow pressure has stabilized. At this point the flow pressure and flow time are recorded and the process is repeated for a different flow rate. Each flow rate must be maintained at a constant value until the flow pressure has "stabilized." The test is complete when four different flow rates and corresponding flow pressures have been recorded. The advantage to running this type of test is that there are no shut-in periods and, consequently, no down time. The disadvantage to this test is that the reservoir must be properly stabilized for each flow rate. If this condition is not met, conventional analysis techniques can fail significantly.

When properly analyzed, the four-point test will help determine (1) maximum well delivery, or AOF rate, which occurs when reservoir pressure is at a maximum and wellbore pressure is at a minimum, (2) productivity forecast for the life of the well (given a reservoir pressure, well deliverability may be calculated), (3) formation characteristics of a well including permeability or permeability/thickness and skin, and (4) formation capacity and drainage volume.

The most rigorous, detailed analysis requires a knowledge of all measured data obtained during the test. However, some very useful information may still be obtained using only the data reported on standard well completion cards, namely: bottom-hole shut-in pressure (BHSIP), four bottom-hole flow pressures (BHFP) at corresponding volumetric flow rates (Q), and reservoir temperature.

Techniques available to analyze four-point test data are each based on an empirical relationship or an approximate theory. The procedure for running the test stipulates stabilized flow must exist; thus, all of these methods use stabilized or semi-steady-state inflow equations. The two methods used during the field screening procedures are the Simplified Analysis and the Pseudo-Pressure Analysis methods. They will be included in future reports on Stratton and McAllen Ranch fields.

Because of the shortness of the flow periods in a typical four-point test, stabilized conditions are often never achieved. Thus, it was necessary to find a method with which to analyze the multirate test data based upon transient flow conditions rather than stabilized flow. The technique used in this case was that of Essis and Thomas and will be described in detail within the reports on Stratton and McAllen Ranch fields. This technique differs from the methods referenced above in that it is based on transient flow theory rather than stabilized flow.

Fields Selected for Detailed Studies

Field screening studies resulted in the identification of Lake Creek, Seeligson, Stratton-Agua Dulce, and McAllen Ranch fields as candidates for further analysis (table 2, fig. 2). These fields contain Wilcox, Vicksburg, and Frio reservoirs, which are among the most prolific gas-producing intervals in South and South-Central Texas. Principal operators are Oryx Energy Company in Seeligson field (unitized Frio reservoirs), Mobil Exploration and Producing U.S., Inc., in Seeligson (nonunit Frio reservoirs) and Lake Creek (Wilcox) fields, Union Pacific Resources in Stratton field (Frio and Frio-Vicksburg transition), Pennzoil in Agua Dulce field (Frio and Frio-Vicksburg transition), and Shell Western Exploration and Production, Inc., in McAllen Ranch field (Vicksburg). The fields have the potential for uncontacted and partly drained reservoir compartments and are representative of the spectrum of fluvial and deltaic sandstone reservoirs in the Texas coastal plain.

INITIAL STUDIES OF SELECTED GAS FIELDS

Initial geological and engineering studies were undertaken in Lake Creek, Seeligson, Stratton-Agua Dulce, and McAllen Ranch fields. The objective of these investigations was an initial evaluation of the interwell reservoir heterogeneity in the fields as a basis for the planning and implementation of infield data collection programs to further define stratigraphic reservoir heterogeneities and related unrecovered gas resources.

Summaries of the data available and a tentative, near-term, infield data-acquisition program are presented for Lake Creek field. Information for this field was received and the investigations were initiated near the end of the research year. The fieldwide stratigraphic and structural framework and the stratigraphy of selected reservoirs in parts of Seeligson, McAllen Ranch, and Stratton-Agua Dulce fields were determined. Initial reservoir-engineering evaluations were conducted for Stratton and McAllen Ranch fields. These data are summarized below. Emphasis is on the Seeligson and McAllen Ranch fields, where new data were collected in new wells with operator cooperation.

Lake Creek Field

Data Base

An extensive geological, petrophysical, geophysical, production, and engineering data base is available from the Lake Creek gas unit (LCU), which is operated by Mobil Exploration and Producing U.S., Inc. Cores, well log suites, completion, and per-well cumulative production data from 46 LCU wells were obtained and cataloged. Nine wells penetrate only the shallow gas reservoirs (La Gloria, 1 through 5, and A). Twenty-six wells reach reservoirs in the middle of the producing interval (sandstones A through H). Sixteen wells penetrate at least part of the deep gas reservoirs (sandstones I through Q). Results of petrophysical core analyses are available for most of the LCU wells. Whole-core chips and slabbed core were loaned by Mobil and were being cataloged by the end of the research year. In addition to the well data, 10 two-dimensional (2-D) seismic sections covering the field were obtained. The sections form part of a 10 × 10-mi grid comprising 24 seismic lines that include the field and surrounding areas. The seismic data were recorded from 1966 to 1983 using a dynamite source and vary considerably in quality. Coverage ranges from 6- to 18-fold. Field tapes of six lines across LCU were received from Mobil (fig. 7).

Infield Data-Acquisition Plans

Mobil plans to deepen the LCU No. 29 well in the last quarter of 1989. The deeper-pool test, which is located in the northeast part of LCU (fig. 7), will be drilled from 9,289 ft, the current total depth, to a final depth of approximately 12,900 ft. The F and G sandstone reservoirs are the objectives. One of the SGR project plans is to conduct a zero-offset vertical seismic profile (VSP) survey in this well, to obtain detailed velocity data for the area and to develop a good tie to a seismic line previously recorded over the well location. Mobil plans a suite of well logs, pressure tests, and use of a wire-line rotary coring tool and has indicated willingness to provide these data to the project.

McAllen Ranch Field

Geology

The McAllen Ranch gas field is located in the Rio Grande embayment of South Texas (fig. 2). The field lies approximately 20 mi east of the Vicksburg fault zone, in the downthrown block of a major growth fault that dips approximately 5 degrees eastward beneath the field and that was active during deposition of lower and middle Vicksburg strata. Vicksburg beds in the field dip westward, toward the fault, forming a shingled set of reservoirs that are younger to the west. Numerous faults cut lower Vicksburg strata, but they generally die out near the top of the lower Vicksburg. These faults are arcuate, northeast-trending, en echelon features that are both down-to-the-basin and antithetic.

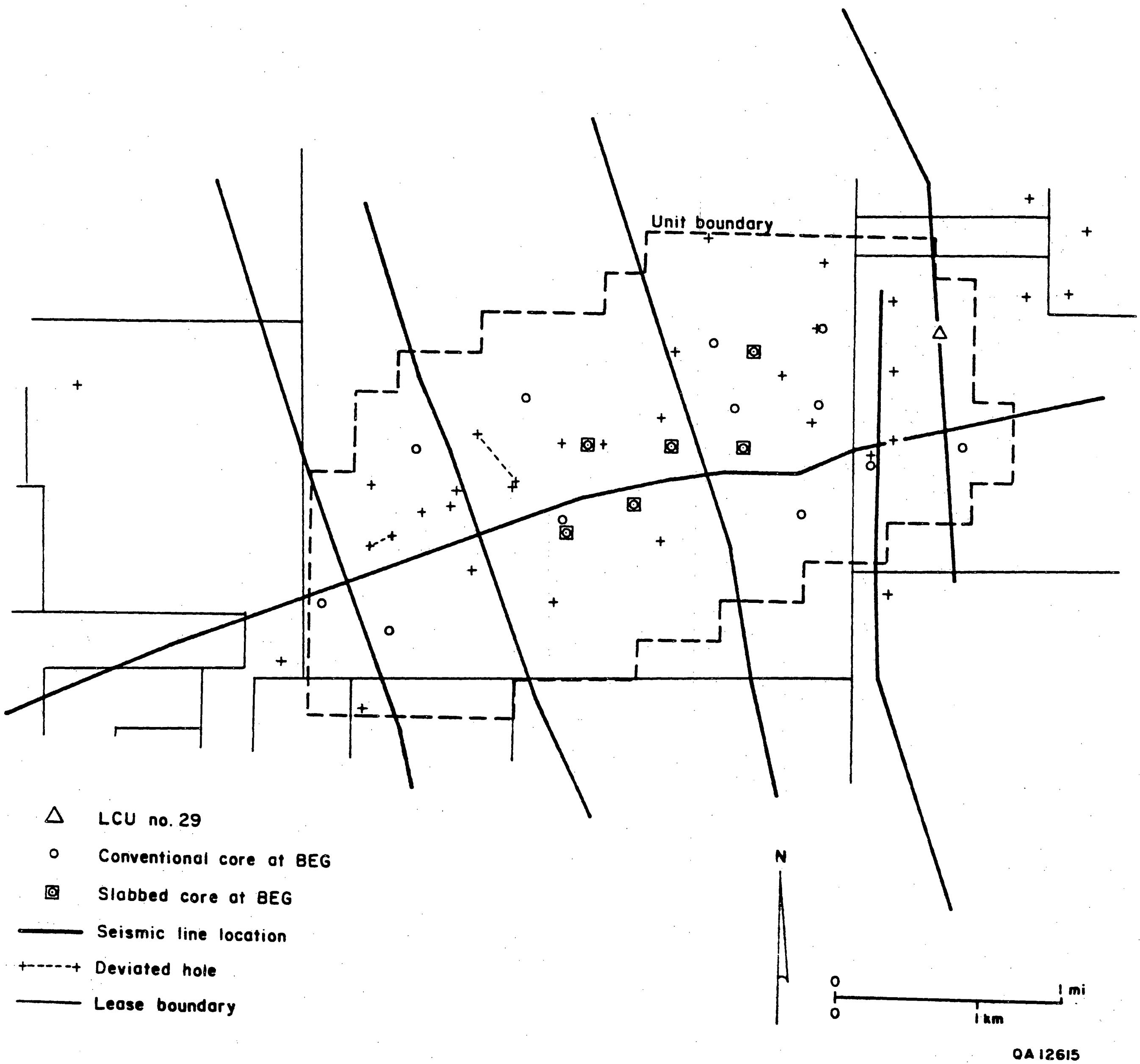

Figure 7. Index map and data base, Lake Creek gas unit, Montgomery County.

The field is located along the eastern (downdip) flank of a large shale diapir within shales of the Jackson Group. Continued warping of the shale and overlying Vicksburg strata during Frio deposition folded the beds into two east-west-trending anticlinal noses, one in the north part of the field (the B area) and another in the south part of the field, which has been more intensely drilled. Shell Western Exploration and Production, Inc., recently recorded a three-dimensional (3-D) seismic survey in the B area and on August 31 spudded the McAllen Ranch No. B-18 well (fig. 8).

The Vicksburg section in the field is divided into a shaly upper portion and a sandy lower interval (fig. 9). Gas reservoirs in the field form part of the sandstone packages that are named J through Y, youngest to oldest. The J and K sandstones are in the upper Vicksburg, and the L sandstone forms the top of the lower Vicksburg Group. P, R, S and U-V are the most productive reservoirs. The sandstone packages were correlated across the field using wire-line logs from 115 wells. Structure and net-sand maps of the J, L, N, P, R, and S sandstone packages were constructed, and maps showing faults in the L, N, P, R, and S sandstone packages were prepared to aid identification of relatively unfaulted areas suitable for study in the SGR project.

Depositional Systems and Diagenesis

Depositional systems of the lower Vicksburg were interpreted using existing Shell cores from 9 wells and wire-line logs from 100 wells. Lower Vicksburg reservoirs form part of the shelf-edge deltas along an active growth fault.

Four sand-rich facies have been identified within the deltaic sandstones from study of the cores: distributary channel, channel-mouth bar, delta front, and distal delta front. In addition, shales form the dominant part of the delta-plain, prodelta, and mud-shelf facies (table 3). In general, distributary channels occur mostly along the northwest edges of the producing areas for each sandstone (fig. 8). Delta-front deposits thin toward the east and northeast.

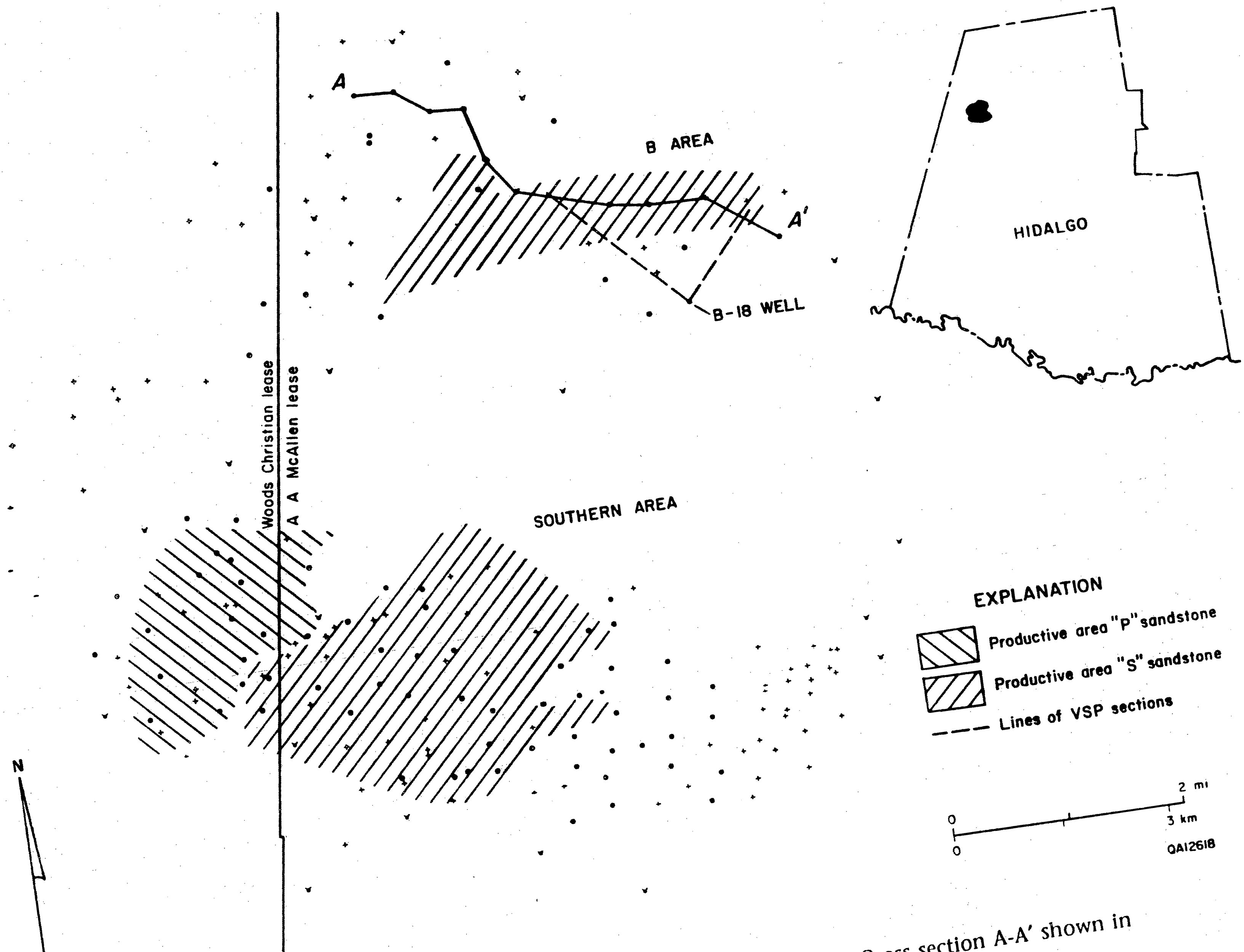

Figure 8. Index map, McAllen Ranch field, Montgomery County. Cross section A-A′ shown in figure 9.

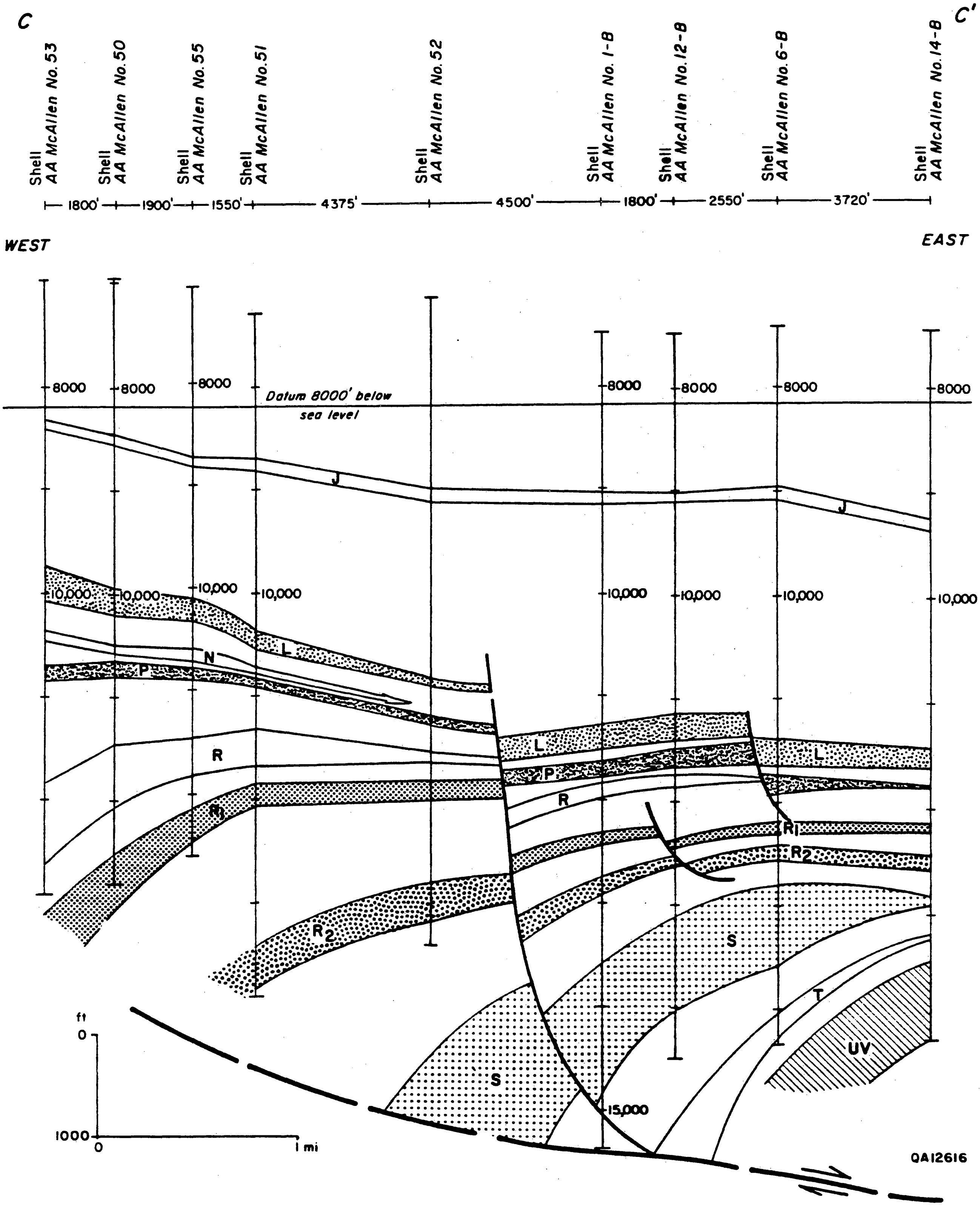

Figure 9. Cross section A-A', north part (area B) of McAllen Ranch field.

Table 3. Facies of the lower Vicksburg, McAllen Ranch field.

Facies	Reservoir quality	Fabric	Internal structure	Sedimentary structures
Distributary channel	Good, best near base	Poorly sorted coarse- to fine-grained sands	Massive, upward-fining	Trough cross strata; crude subhorizontal laminae
Channel-mouth bar	Best near top	Medium to very fine grained in thin upward-fining beds	Massive, with upward-fining and -coarsening trends	Trough cross strata; laminae, ripples, soft sediment deformation
Delta front	Good, best near top	Fine to very fine grained in thin upward-fining beds	Massive, upward-coarsening	Sequences of massive-laminae ripples
Distal delta front	Poor	Very fine grained sand to silt in thin upward-fining beds	Upward-coarsening with 1- to 3-ft beds interbedded with thin shales	Sequences of laminae ripples, deformed beds
Delta plain and shelf	None	Clay, massive or laminated	A few thin silt beds	Thin laminae, plant remains

Comparison of facies, porosities, and permeabilities indicates that channel and channel-mouth-bar sandstones are the best reservoirs. Furthermore, these facies are laterally discontinuous and offer the best potential for reservoir compartmentalization. The channel facies usually occur as laterally discontinuous deposits that cap progradational delta-front facies and consist of poorly sorted, medium- to coarse-grained sandstones displaying trough cross-stratification and crude subhorizontal laminae. Channel-mouth-bar facies are thick sandstones that thin away from the distributary channels. Channel-mouth-bar deposits comprise massive sandstones and thin, upward-fining beds, the latter beds forming barriers to vertical fluid flow. Extensive slumping and thin shale beds within this facies create potential permeability barriers.

The more laterally extensive delta-front facies is the next highest in reservoir quality. This facies is similar to channel-mouth-bar deposits, but exhibits better defined upward-coarsening trends and is more laterally continuous. Distal delta-front, delta-plain, and mud-shelf facies form permeability barriers that isolate reservoir compartments.

Results of the study of more than 200 thin sections of core samples were compared with lithofacies and petrophysical data. Initial results indicate that three diagenetic facies are dominant within the field: (1) calcite cement, which has almost completely filled the pores in very fine grained sandstones, (2) chlorite cement, which precipitated in the pores of coarser grained sandstones that constitute the majority of the reservoirs in the field (and have porosities between 18 and 20 percent but very low permeabilities due to pore-filling clay cement), and (3) early-formed quartz cement, which is common in the coarsest sandstones (typically less than 3 ft thick and having the best porosities and permeabilities providing isolated flowpaths for gas production).

Reservoirs Studied

The P and S sandstone reservoirs were chosen for more detailed study because (1) they contain numerous productive wells within individual fault blocks, (2) a long production history in the south part of the field indicates that these reservoirs are at a mature stage of development, (3) the two reservoirs have produced most (73 percent) of the total gas, and (4) REC's initial engineering assessments suggested that infill wells in these reservoirs were found near virgin reservoir pressures, suggesting compartments untapped because of stratigraphic reservoir heterogeneity.

The P sandstone. The P sandstone package was correlated using a grid of nine cross sections. It contains a single progradational interval forming a wedge that is more than 500 ft thick on the west edge of the field and thins and pinches out abruptly in the south-central portion of the field (fig. 8). The P sandstone produces from the west portion of the field. The interval comprises mostly upward-coarsening, delta-front sandstones in the north and southeast parts of its producing region. Production is most prolific in the east part of the field, where upward-fining, distributary-channel sandstones predominate.

The S sandstone. The S sandstone package was correlated using a grid of 12 cross sections. It forms a gently tapering wedge that thins from several thousand feet along the northwest edge of its producing region to 200 ft in the southeast corner of the field (fig. 8). It comprises five progradational, sand-rich deltaic intervals that, from youngest to oldest, are named S_1 through S_5. Each interval is vertically separated by shales that are continuous across the field. The S_1 and S_5 intervals are dominated by delta-front sands. The S_3 and S_4 intervals contain numerous distributary channels that are discontinuous between wells. The S_2 interval contains massive channel-mouth-bar and delta-front sandstones along with distributary channels.

Net-sand maps of the more intensely drilled, south part of the field indicate that lobate sand thicks form much of the S (fig. 10) and P sands. The lobate character, interpreted to result from the deposition of small delta lobes, suggests that sand continuity is low and that the S sandstone package in particular may contain several untapped gas compartments within the delta lobes and untapped distributary channels. Dwight's production data from this area indicate that fieldwide cumulative gas production in 1985 totaled approximately 540 Bcf, of which 118.6 Bcf is from the P reservoir, 53.5 Bcf is from R reservoirs, 269.7 Bcf is from S

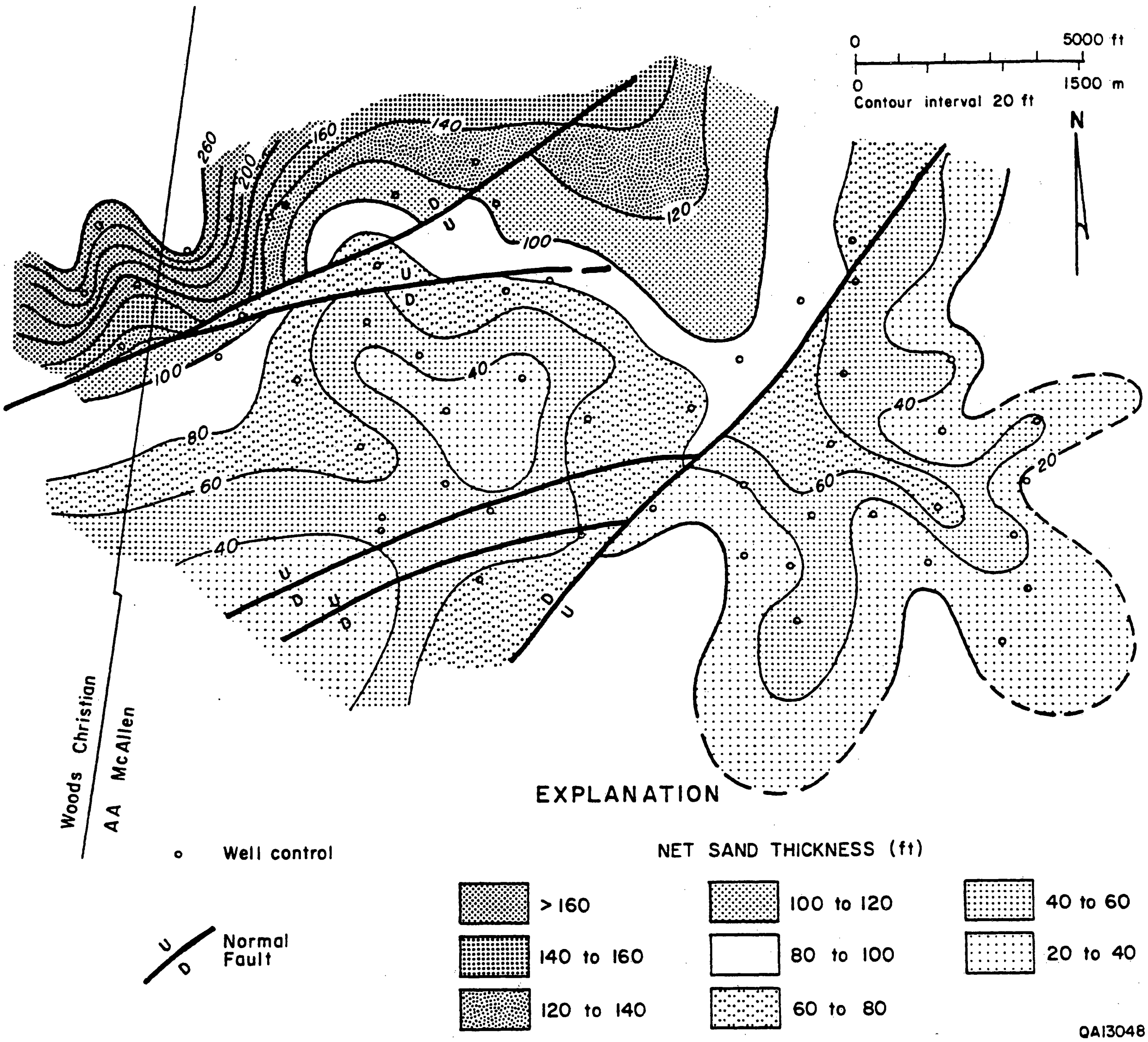

Figure 10. Net sandstone map, S_1 sandstone, south part of McAllen Ranch field.

reservoirs, 4.3 Bcf is from T reservoirs, 53.4 Bcf is from UV reservoirs, and 27.8 Bcf is from Y reservoirs. Certain fault blocks are more productive than others, but the relative importance of stratigraphic and diagenetic controls on production is as yet unknown. An attempt was made to analyze gas production relative to principal facies, but the standard field practice of perforating long intervals, often exceeding 500 ft, thwarted this approach. There is not a clear relationship between the productivity of single wells and the height of the perforated interval (fig. 11).

Engineering Assessment

An initial engineering study was conducted on the McAllen Ranch field by REC to determine which, if any, of the producing reservoirs in the field exhibit indications of compartmentalization (Research and Engineering Consultants, 1989a). To accomplish this, it was necessary to describe the production character of the various reservoirs within the field and, where possible, make certain quantified analyses regarding permeability-thickness products, initial potentials, and exponential decline rates.

P,N Sandstone

For the P,N sandstone, the Initial-rate and Q-ratio plots show a rather mixed behavior with time. If one concentrates on the four most recently completed wells in the group, however, a case can be made for compartmentalization within the P,N sandstone. Two of the wells have initial annual average rates in excess of 1 MMcfpd. One of the wells, the A. A. McAllen 67R, was originally completed in the R sand in 1980 and was recompleted in the P,N sand in 1985. Since that time, the well has shown very little decline in rate and has averaged quite a bit above 3 MMcfpd. Further, one of the other P,N wells, the A. A. McAllen 79, tested a pressure of 8,168 psi at 10,800 ft upon completion in June 1987. This high pressure, coupled with the production character of the 67R and other P,N wells, suggests stratigraphic

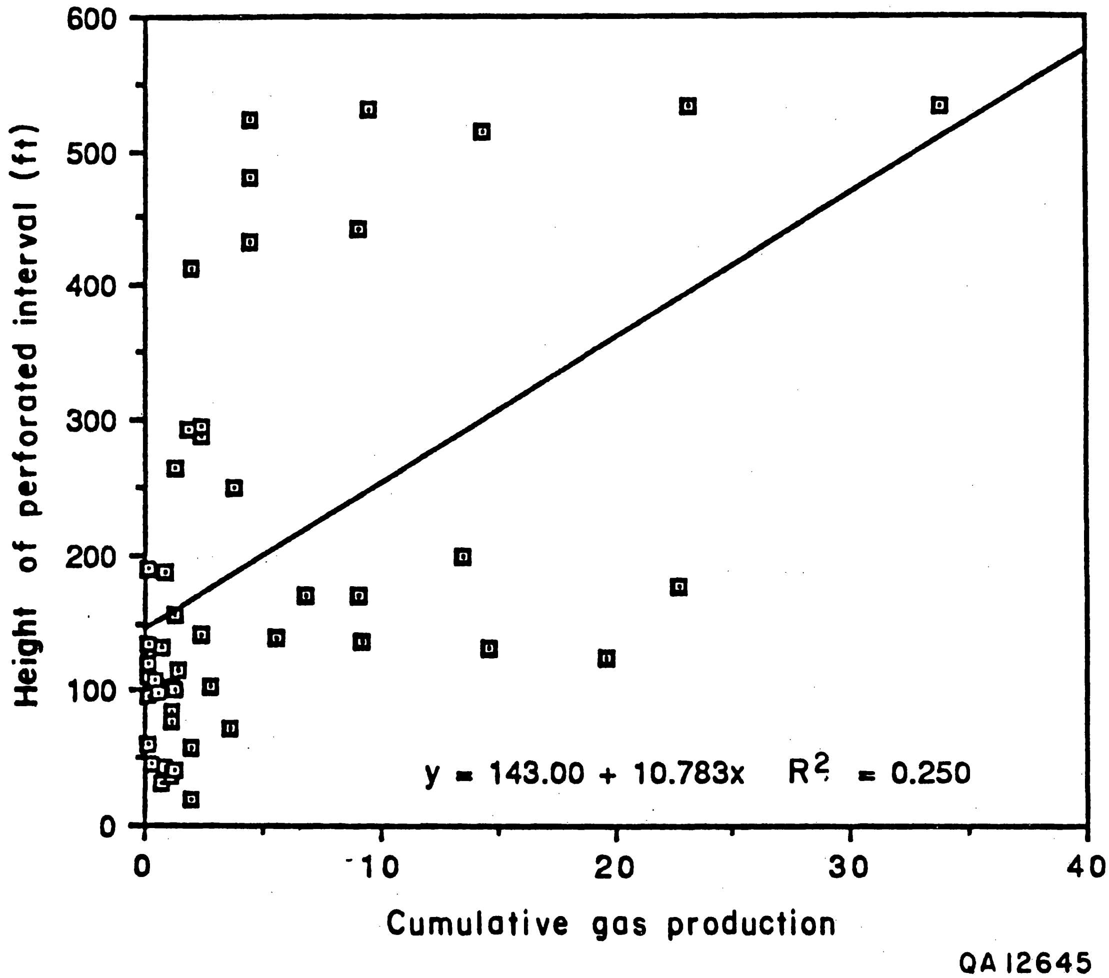

Figure 11. Scatter diagram of cumulative gas production and height of perforated interval. Line fitted to scattergram illustrates poor correlation (R^2 = 0.25).

compartmentalization within the reservoir. These characteristics could also result from a small drainage radius due to low permeability. Evaluations are under way to assess the relative importance of these factors.

R and R-1 Sandstones

There is a clear trend for the Initial-rate plot, although the production data for these reservoirs exhibited considerable scatter (fig. 12). Similarly, the Q-ratio plot shows scatter, but early and late wells seem to fall essentially on the same decline curve (fig. 13). These characteristics indicate compartmentalization. They also reflect the effects of small drainage radius due to low permeability.

S; S,N; S,S; and S,SE Sandstones

Upon inspection of S sandstone wells having anomalously low decline rates (around the 10-percent curve), it was discovered each of these wells was worked over in the mid-1980's, resulting in a substantial increase in production rate. In most cases, the increase was a three- to five-fold jump in rate, although in one case (A. A. McAllen No. B-2) the increase was more than 10 times the previous rate. A dramatic increase in rate late in the life of a well will obviously affect the Q-ratio, making the well "appear" to have a lower decline rate.

The most conclusive evidence to support compartmentalization in the S sandstone is found in BHP/Z data from these wells. A P/Z versus cumulative production plot is a graphic representation of a material balance on a gas well. The data should theoretically form a straight line which, when extrapolated to an estimated P/Z at abandonment, will yield the ultimate production for the well. Deviations from "straight-line" behavior are usually the result of changes in the drainage volume—a decrease in slope corresponding to an increase in volume contacted and vice-versa.

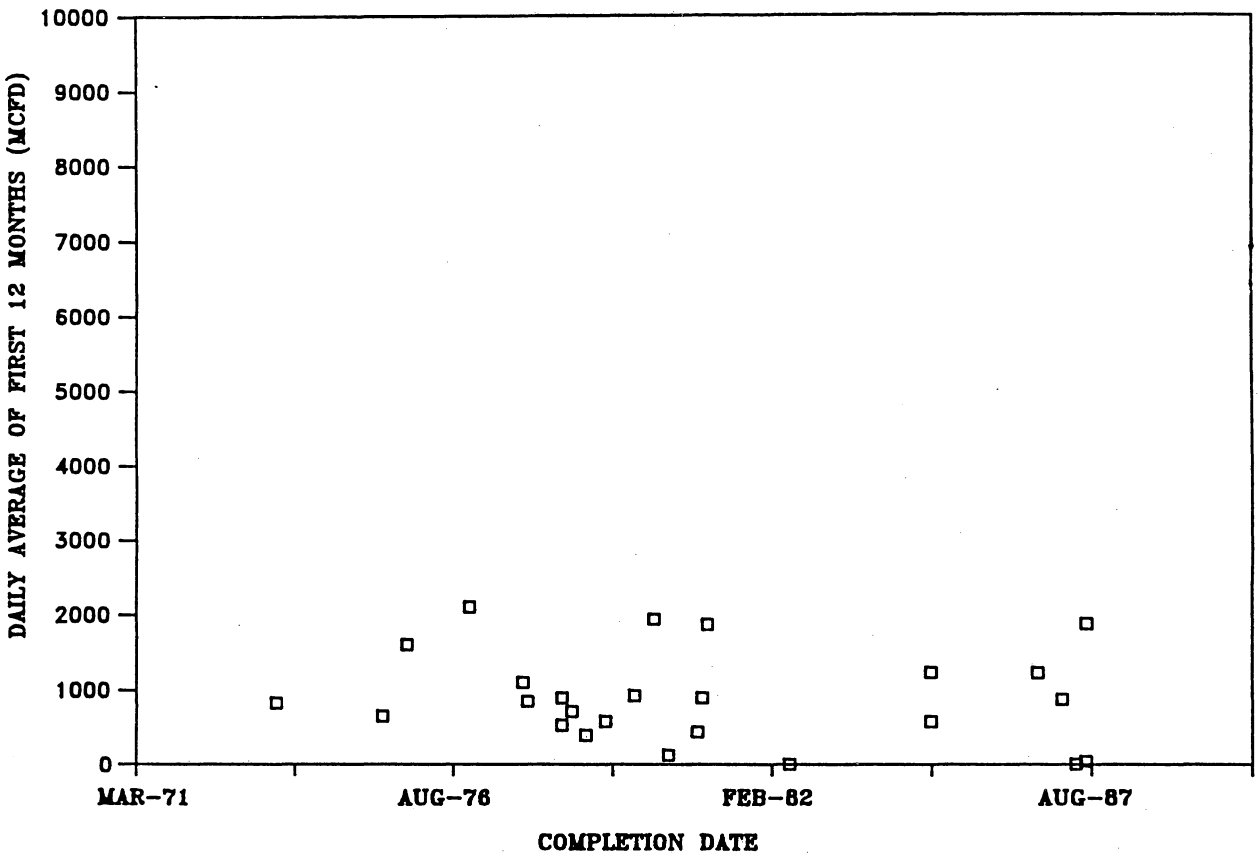

Figure 12. Initial-rate plot of wells drilled after January 1970, R and R-1 sandstones, McAllen Ranch field.

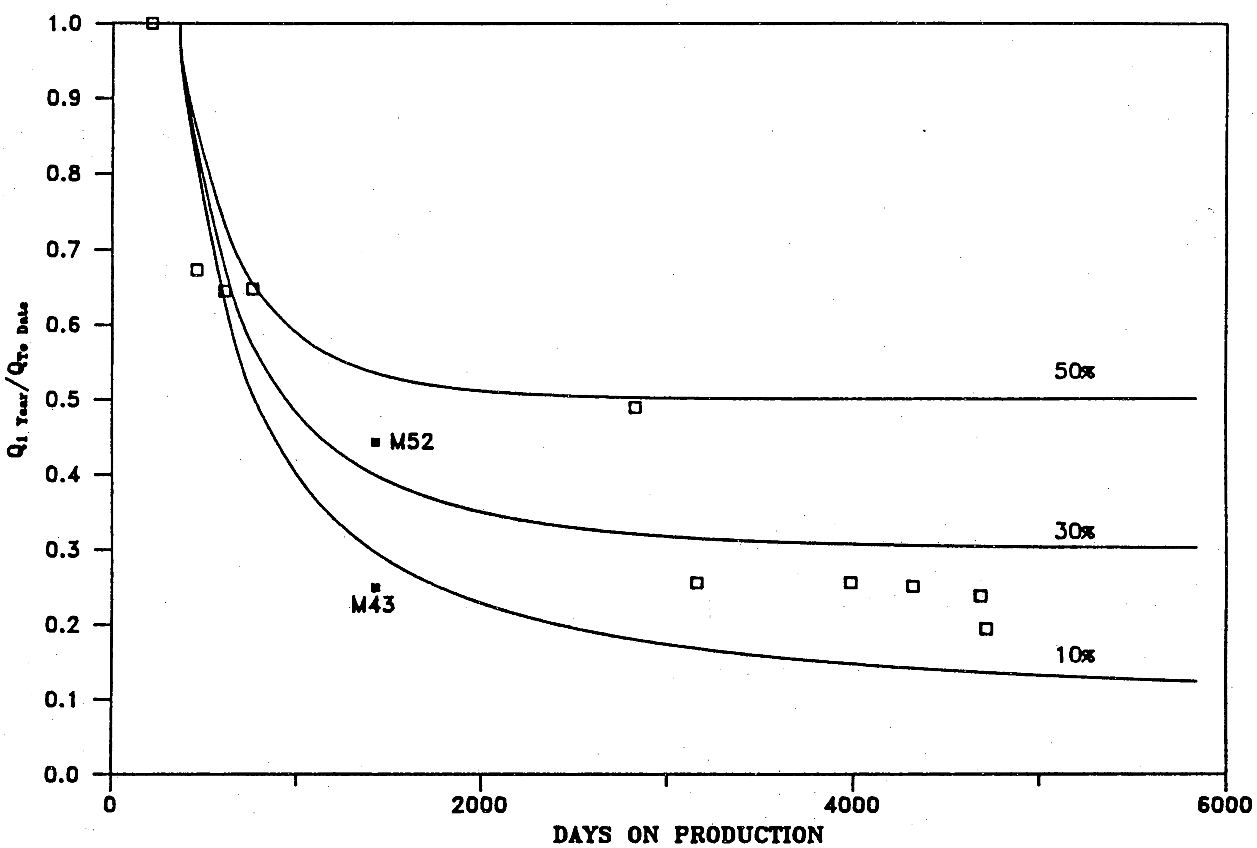

Figure 13. Q-ratio plot of active wells drilled after January 1970, R and R-1 sandstones, McAllen Ranch field.

In many of the P/Z plots for the S sandstone wells, the BHP/Z values show a gradual leveling off as cumulative production increased (fig. 14). This leveling off of BHP/Z data is critical in that in the absence of water drive it is indicative of compartmentalization within the reservoir. An increase in the drainage volume of α will decrease the slope of the BHP/Z curve. The fact that it is a gradual change implies that the reservoir is either expanding with time, which is highly unlikely, or that there is a steady recharge from some untapped, adjacent reservoir. Thus, it is concluded that the S, the S,N, the S,S, and the S,SE sands appear to be compartmentalized and are excellent targets for the SGR project to consider.

U-V,SE Sandstones

In terms of cumulative production, the U-V,SE sandstone has been the most prolific reservoir in the McAllen Ranch field, considering post-January 1970 completions. The Initial-rate plot shows no apparent decrease in initial potential rates with time. In fact, of the 21 wells completed in the reservoir in the 1980's, only one has had an initial year average below 1 MMcfpd. The sandstone should thus be considered as a target for further development. Furthermore, the Q-ratio plot shows a historical trend of low decline rates. The above data suggest that the U-V,SE sandstone is, for the most part, a reservoir not experiencing significant pressure depletion.

Considering the amount of drilling in the U-V,SE sandstone over the years, and the performance of the most recently completed wells, compartmentalization within the horizon is probable. It is unlikely that the production character is simply the result of continued lateral extension of the reservoir limits.

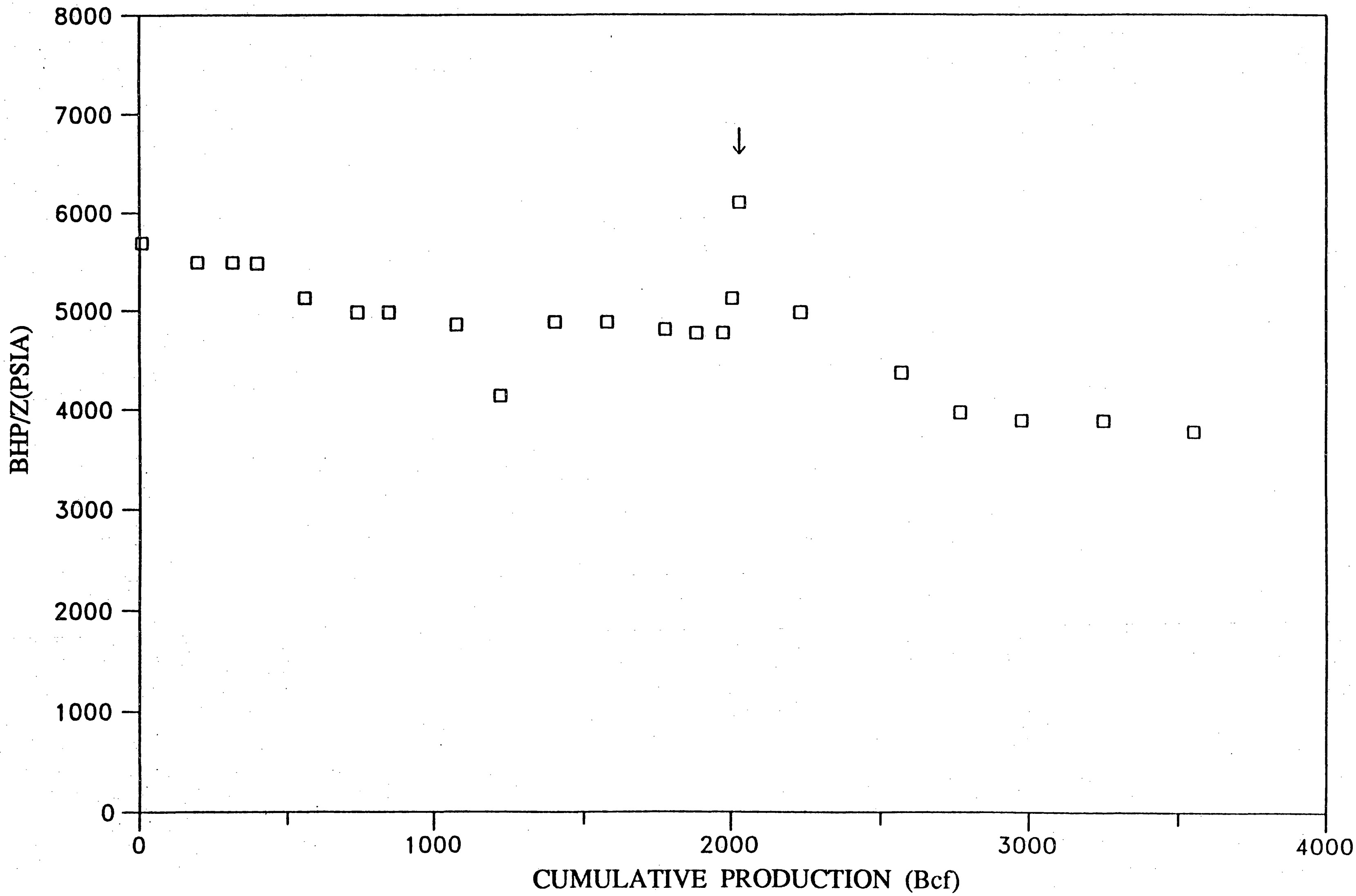

Figure 14. P/Z graph, S sandstone, McAllen Ranch field.

Y Sandstone

The Y sandstone has also been the target of much activity in the McAllen Ranch field. Since 1970 it has been the second most frequently drilled horizon and the second most prolific in terms of cumulative production. However, since 1984 no wells have been successfully completed in the Y sandstone.

The Initial-rate and Q-ratio plots show signs of a depleted interval—a historical decrease in initial production rates with a corresponding increase in production decline rates with time. Additionally, BHP/Z data analyzed for wells worked over during the mid-1980's do not support reservoir compartmentalization or the presence of a "leaky" barrier. Here there is no gradual leveling off of the data with time. Therefore, the Y sandstone is not considered a candidate for study of reservoir compartmentalization at this time.

Guerra Sandstone

Production history of the Guerra sandstone is too short to reveal any strong signs of reservoir compartmentalization. Additional drilling and production from the zone is necessary before any definitive conclusions may be drawn.

Data Acquisition in Cooperative Wells

A formal proposal was made to conduct a cooperative data-acquisition program with Shell Western Exploration and Production, Inc., during the drilling of the recently spudded Shell McAllen Ranch No. B-18 well. The program was designed to integrate geophysical, geological, petrophysical, and reservoir engineering data to describe reservoir characteristics of the S sandstone package in the B area (fig. 8). Data acquisition was under way at the end of the research year. The plan includes collecting 360 ft of whole core, of which 120 ft will be oriented, in four intervals in the S sandstone package. Petrophysical data to be acquired by the project will supplement Shell's formation-evaluation program by including a full-waveform acoustic log for shear- and compressional-velocity data, formation-density and gamma-ray logs for use in synthetic seismograms, and sidewall cores to provide additional samples for mineralogic analysis.

Acquisition of sequential formation-pressure data is programmed in potentially productive zones, to determine reservoir pressures in individual sandstones for evaluation of the degree of communication and interpretation of pressure and production data. McAllen Ranch Nos. B-2, B-4, and B-15 wells currently produce from various S sandstone intervals within a one-half-mile radius of the McAllen Ranch No. B-18 well. The formation-pressure testing proposed will aid in interpretations of deliverability and material balance data available on the existing producing wells and will facilitate evaluation of vertical communication among intervals being produced. As many as 40 tests are envisioned, including multiple tests in several intervals.

VSP's will be recorded in three runs: (1) open hole from 5,000 ft to surface, (2) cased hole from 9,700 to 5,000 ft, and (3) cased hole from 14,000 to 9,700 ft. The program consists of (1) a zero-offset located within 400 ft of the wellbore; it will provide velocity calibration for synthetic seismograms, well logs, and depth conversion of 2-D and 3-D seismic data near the B-18 well; (2) a 5,000-ft offset through a proposed offset well (Shell McAllen Ranch No. B-17); it will provide information about reservoir stratigraphy and structure in the interwell area; and (3) a 8,000-ft offset through the Shell McAllen Ranch No. B-15, a producing well; it will provide geological data in the interwell area and enhance the interpretation of pressure interference tests that may be acquired in a future data-acquisition program.

Stratton and Agua Dulce Fields

Stratton field is located at the common juncture of Nueces, Kleberg and Jim Wells Counties (RRC District 4). Agua Dulce field lies immediately northeast of Stratton field, in Nueces County. Both fields are approximately 10 mi long and 5 mi wide. Because the two fields are similar stratigraphically and structurally, they have been investigated concurrently in this project. Approximately 500 wire-line logs from the Stratton and Agua Dulce fields have been acquired; most are from Agua Dulce field. A large set of completion cards were also acquired giving a near complete coverage of the gas cap for both fields.

Stratton field was discovered in 1937 when a completion was made in the Comstock reservoir. More than 300 gas wells, having multiple completion intervals, have produced approximately 2.6 Tcf of gas. More than 50 wells have been completed in the last year (fig. 15). Approximately 270 Miocene, Frio and Vicksburg reservoirs ranging in depth from 1,500 to 9,000 ft have been discovered (fig. 16). About 120 reservoirs lie in the middle Frio.

Agua Dulce field was discovered in 1928. Approximately 290 reservoirs have produced 307 Bcf of gas from Miocene, Frio, and Vicksburg sands ranging in depth from 1,900 to 9,800 ft (fig. A-13, p. 146). Of those reservoirs identified to date having cumulative productions in excess of 1 Bcf, the majority are in the Frio (34 reservoirs); Vicksburg reservoirs rank second (14 reservoirs), and Miocene reservoirs rank third (2 reservoirs). The middle Frio contains about 160 total reservoirs—having produced a total of 148.5 Bcf. Pennzoil conducted a drilling and work-over program in the 1970's and early 1980's that included 52 wells. Of the new completions reported for the Frio and Vicksburg, 52 percent were "new pay" discoveries or middle Frio reservoirs having near-virgin pressure. The remaining were completed in mostly virgin and overpressured reservoirs in the lower Frio and upper Vicksburg. Union Pacific Resources has had similar results from recent drilling activity within Agua Dulce field.

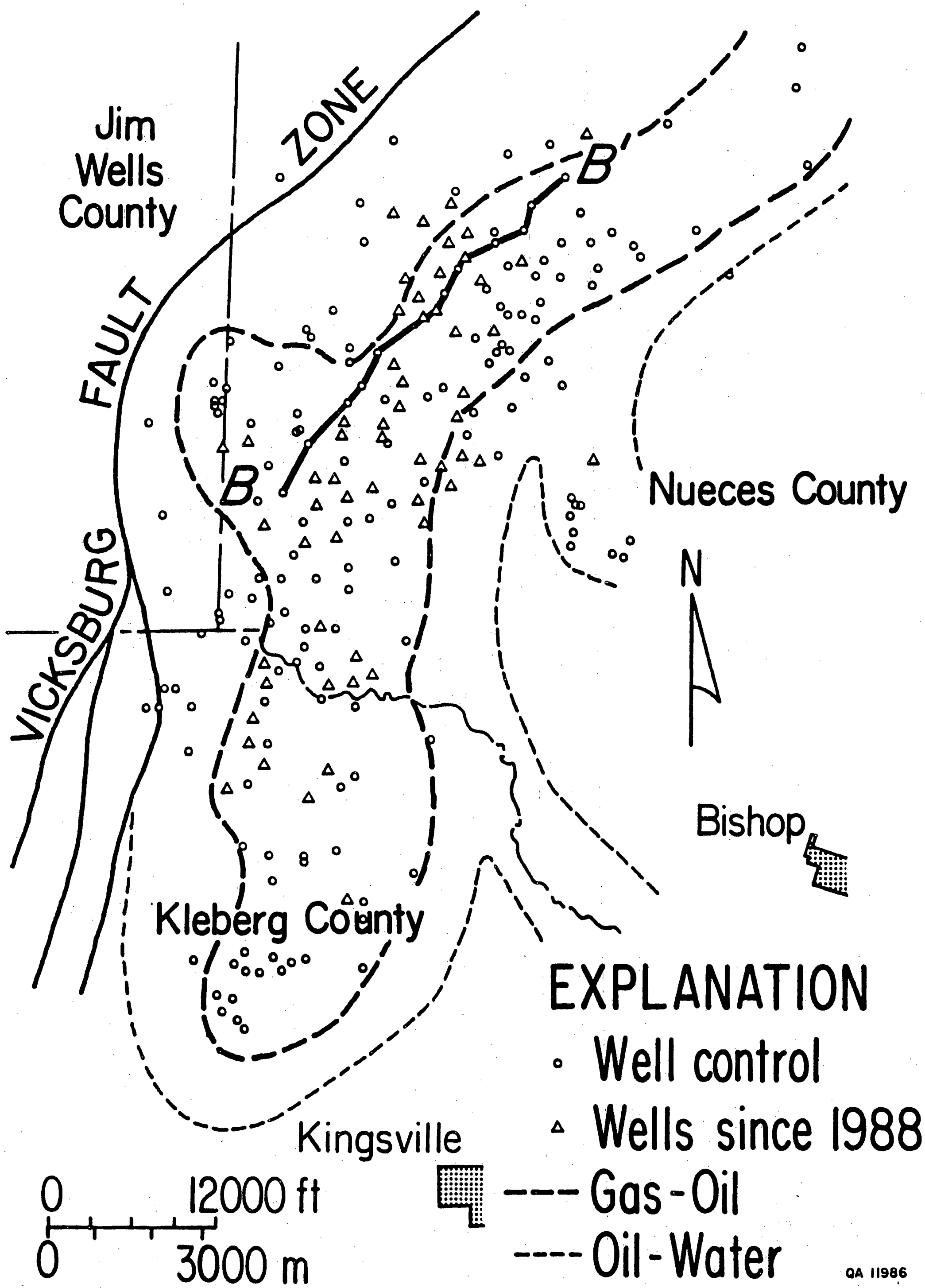

Figure 15. Index map, Stratton and Agua Dulce fields. More than 50 wells have been completed in the field since January 1988. Cross section B-B′ shown in figure 16.

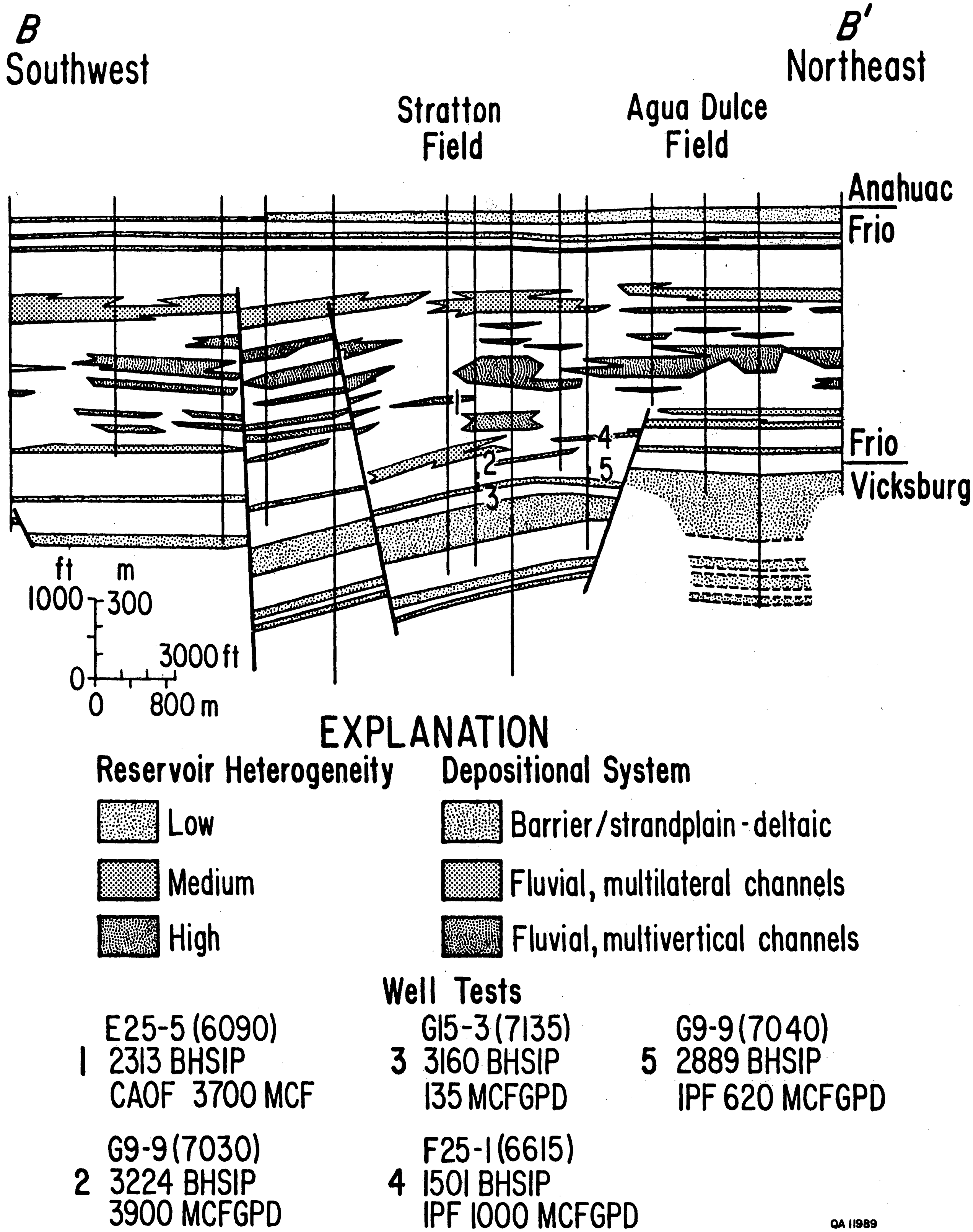

Figure 16. Stratigraphic cross section B-B', Stratton and Agua Dulce fields, and results of selected recent infill wells.

Geology

Stratton and Agua Dulce fields are located in the Rio Grande embayment, basinward of the regionally extensive Vicksburg fault zone. The fields, which are included in plays Frio FR-4 and Vicksburg VK-1, are defined by structural rollover anticlines on the downthrown side of the Vicksburg fault zone. Each field comprises multiple broad anticlinal closures at depths of about 5,500 ft below sea level. The structures become complexly faulted at depths of about 6,500 ft below sea level. Fault patterns include down-to-the-basin normal faults having several hundred feet of throw and counterregional faults having more limited throw; these faults are more numerous to the northwest of each field, near the Vicksburg fault zone. The presence of accommodation faults having lateral displacements is also suggested in cross-section profiles; these faults cut up to the top of the Frio and may have had some impact on Frio sedimentation patterns. Although faulting is complex and needs to be considered, the scale and distribution of faults are such that stratigraphic heterogeneity in the middle Frio is not broken across the entire field. The upper Frio sandstones are laterally continuous but are not important reservoirs in Stratton or Agua Dulce fields.

Engineering Assessment

An initial engineering study was conducted on wells completed in the E, F, and G sandstones that are currently produced by Union Pacific Resources (Research and Engineering Consultants, 1989b). The primary objective of the investigation was to determine which, if any, of the reservoirs in Stratton field exhibit compartmentalization.

E Sandstones

Initial-rate and Q-ratio plots for all the completions in the E sandstones (figs. 17, 18) show that the bulk of the wells completed during the last three to five years remain within the area of shallow decline. No increase in decline was observed in comparison with the oldest wells in the field. In addition, values for the first year average rates show little change with completion date. The newer wells are apparently not experiencing any significant pressure depletion due to earlier offset wells. These data are consistent with potential reservoir compartmentalization within the E sandstones.

Upon segregating the E sandstones into subintervals and repeating the analysis, it was conclluded that the E-31 and Sellers sandstones show the best evidence of reservoir compartmentalization.

F Sandstones

The production data for the F group of sandstones present a different picture. Whereas the oldest wells fall within the shallow decline range on the Q-ratio plot, most of the recent drilling shows wells having declines steeper than those of the older wells. Coupled with this is a trend of initial potentials decreasing with date of completion. This suggests that wells completed in the F sandstone show some pressure depletion due to earlier offset wells. Thus, the F sandstone shows fewer engineering indications of reservoir compartmentalization.

Preliminary analysis of the F sand subintervals reinforces this conclusion, with individual horizons not showing strong indications of reservoir compartmentalization.

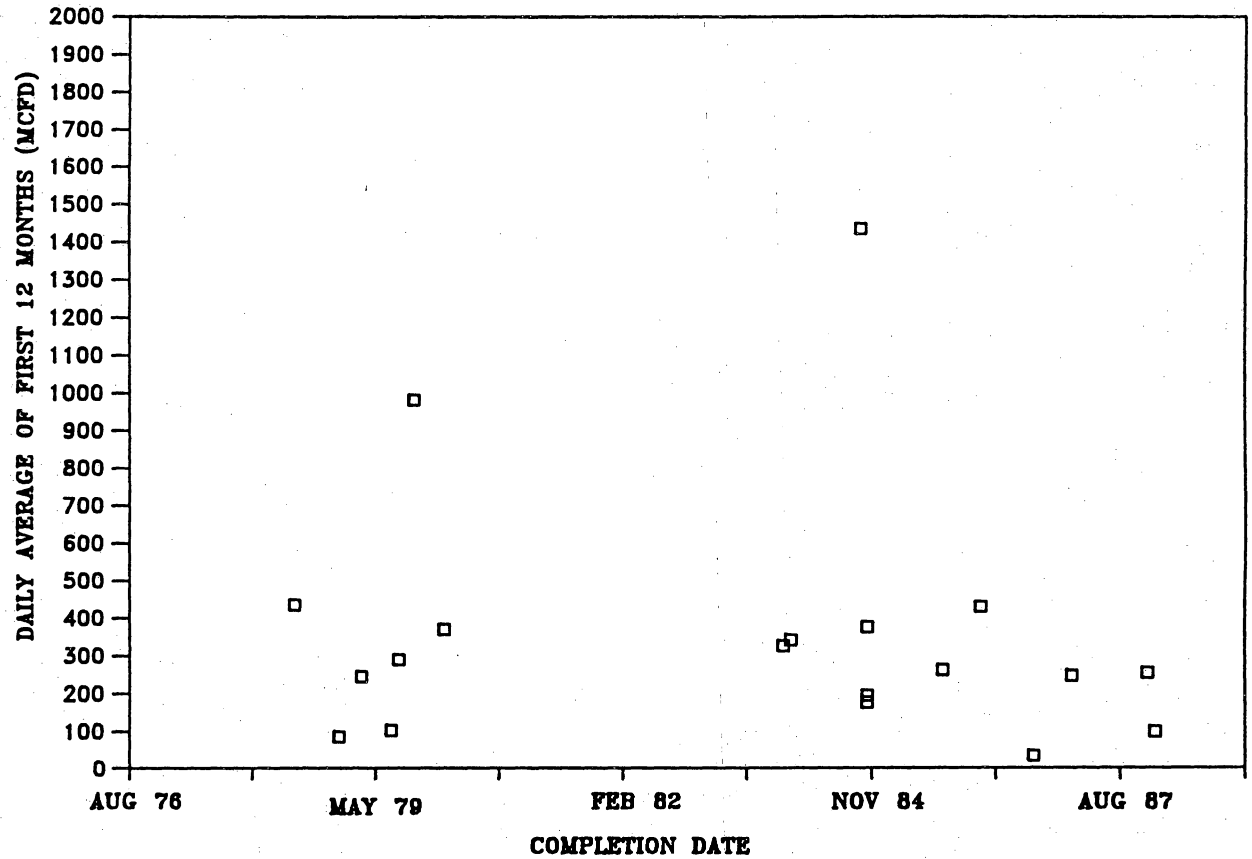

Figure 17. Initial-rate plot of wells completed by Union Pacific Resources between 1975 and 1987, E sandstone, Stratton field.

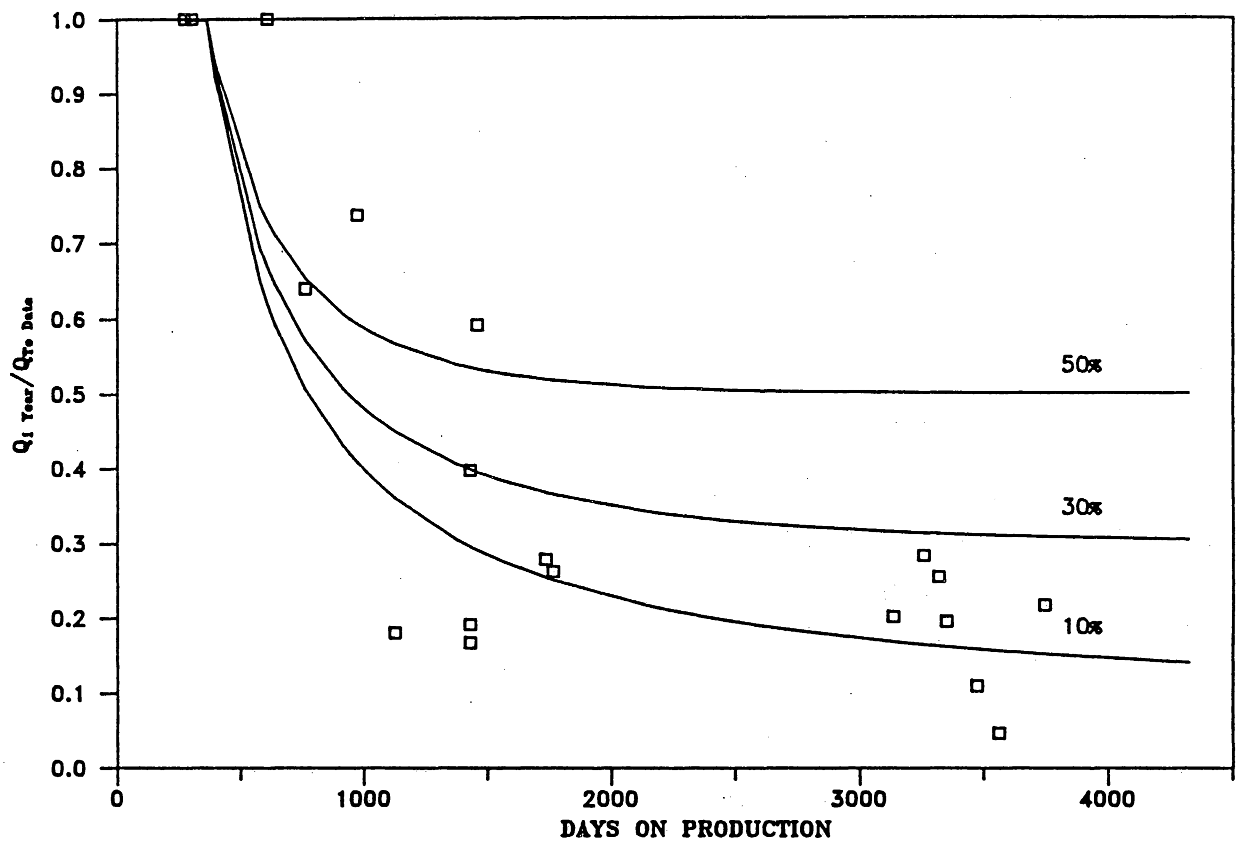

Figure 18. Q-ratio plot of wells completed by Union Pacific Resources between 1975 and 1987, E sandstone, Stratton field.

G Sandstones

The G sandstones show a character intermediate between that observed in the E sands and that observed in the F sands. The oldest G sand completions show much more scatter on the Q-ratio plot than do the other two zones. This may be an indication of a more heterogeneous formation containing some smaller, isolated pockets or compartments that would correspond to the steeper decline rates. The more recent wells show the same pattern, some wells in the shallow decline portion and some in the steeper region. Since the scatter persists over the entire range of the plot, it is likely that some sort of compartmentalization does exist.

The Initial-rate plot is also difficult to interpret due to scatter of the data. If the two highest points are disregarded, there is essentially no decrease in initial rate with time. In addition, the fact that the rates range from under 100 Mcfpd to about 1,000 Mcfpd irrespective of completion date indicates a more heterogeneous but compartmentalized reservoir. The presence of relatively high initial average production in recently drilled wells is encouraging and points to new wells testing at or near virgin pressure. Thus, compartmentalization in the G sand almost certainly exists. An analysis of the subintervals of the G sand shows that the G-9 and G-15 sands exhibit the strongest indications of reservoir compartmentalization.

Seeligson Field

Geology

Seeligson field lies in the highly prolific Frio fluvial-deltaic hydrocarbon play along the margin of the Vicksburg Fault Zone in South Texas. Characteristic of the fields in this play, Seeligson field is composed of multistoried and multilateral reservoirs containing hydrocarbons trapped primarily in rollover anticlines downdip of the major Vicksburg fault. The complex depositional architecture of these reservoirs makes it probable that gas is contained in undrained compartments. Additionally, bypassed gas may be encountered within or uphole from a producing interval.

Study Area and Data Base

Seeligson field is located in Jim Wells and Kleberg Counties, north of the town of Premont (fig. 19). The field is bounded updip by a large northeast-southwest-trending growth fault that offsets Frio sandstones several hundred feet. The eastern, downdip boundary of the field is defined primarily by the limits of production because no significant bounding faults segment the field into a well-defined block. Studies focused primarily on unitized Frio reservoirs in Tract 1, a 20-mi^2 area within the A. A. Seeligson lease of Seeligson field (fig. 20).

The data base contains approximately 200 electric logs that were mostly provided by Oryx Energy Company. In addition, well-history summaries, well-bore sketches, drilling reports, and production data were made available by Oryx. Mobil Exploration and Producing U.S., Inc., provided similar data for wells producing from nonunitized reservoirs and also contributed seismic data to assist in the interpretation of nonunit reservoirs. In May and June of 1989, Mobil drilled two deeper-pool tests in the field, the Mobil A. A. Seeligson Nos. 247 and 248 wells (fig. 20).

Structure and Stratigraphy of Unit and Nonunit Reservoirs

The structure in Tract 1, Seeligson field, is characterized by a northeast-southwest-trending rollover anticline associated with a major Vicksburg growth fault. Reservoirs are Frio and Vicksburg fluvial and deltaic sandstones at depths ranging from about 4,000 to 8,000 ft (fig. 21). More than 40 separate sandstones have been identified, which give rise to more than 130

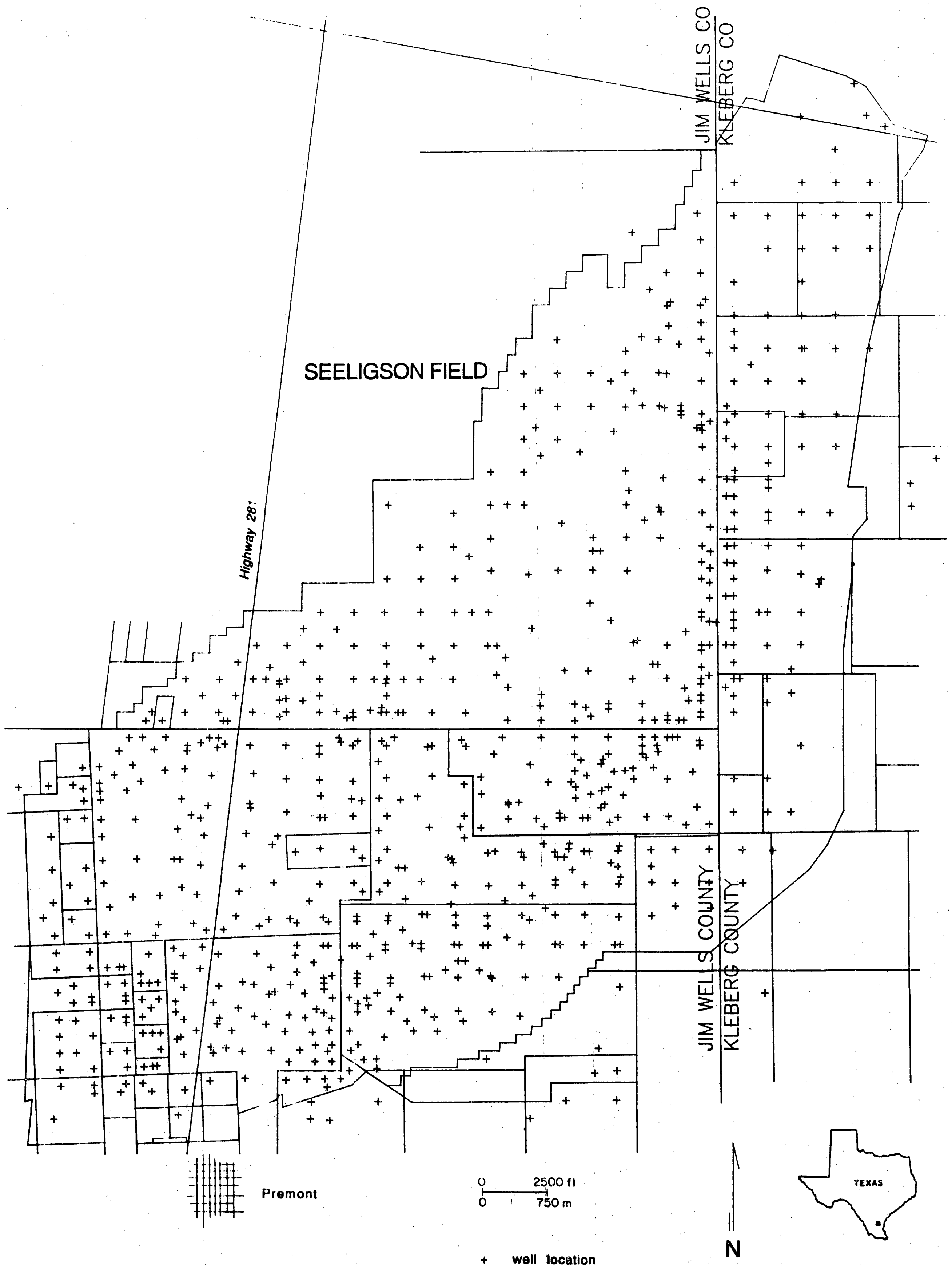

Figure 19. Index map of Seeligson field, Jim Wells and Kleberg Counties.

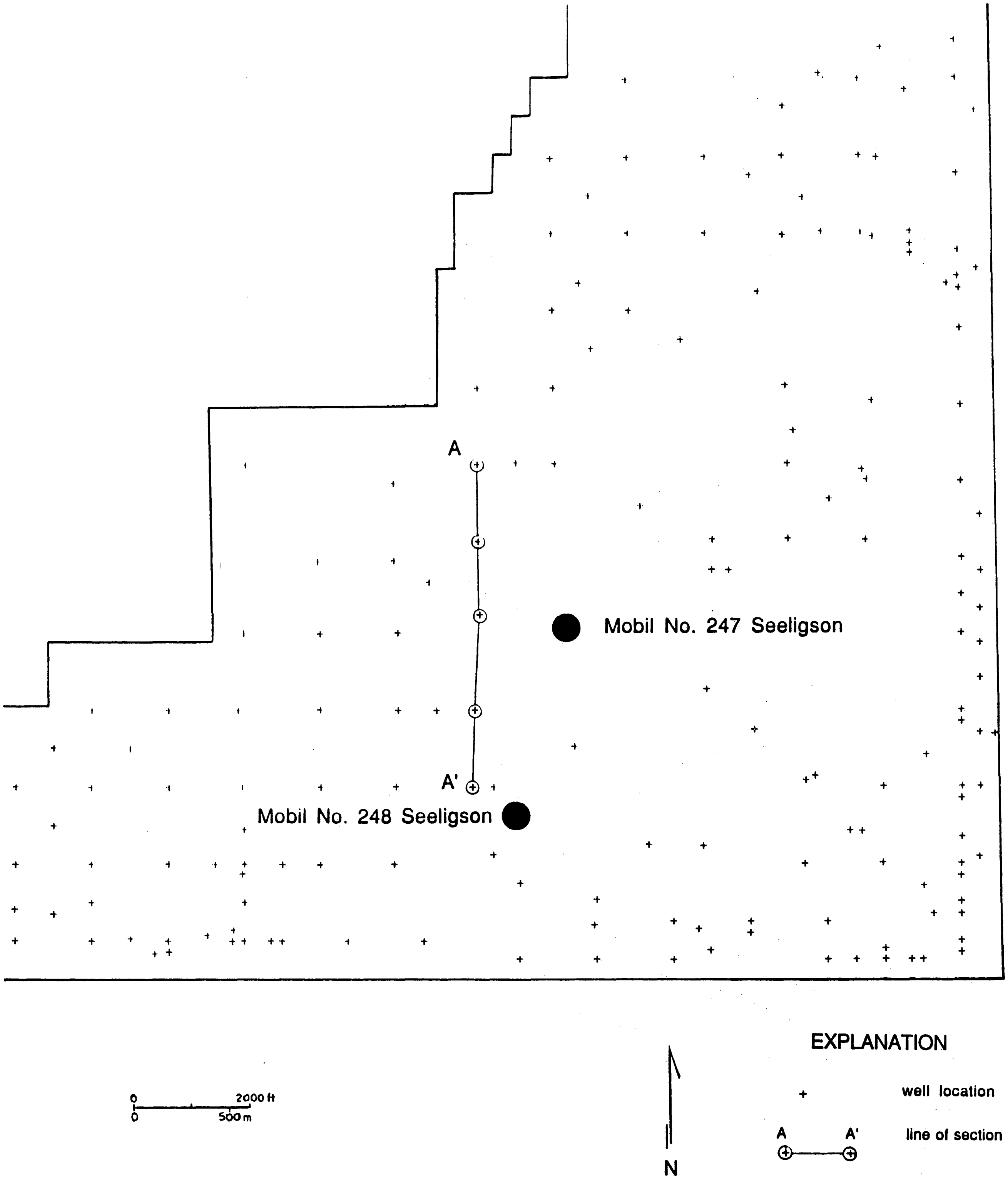

Figure 20. Index map of Tract 1, Seeligson field, showing well locations and Mobil cooperative wells. Section A-A' shown in figure 21.

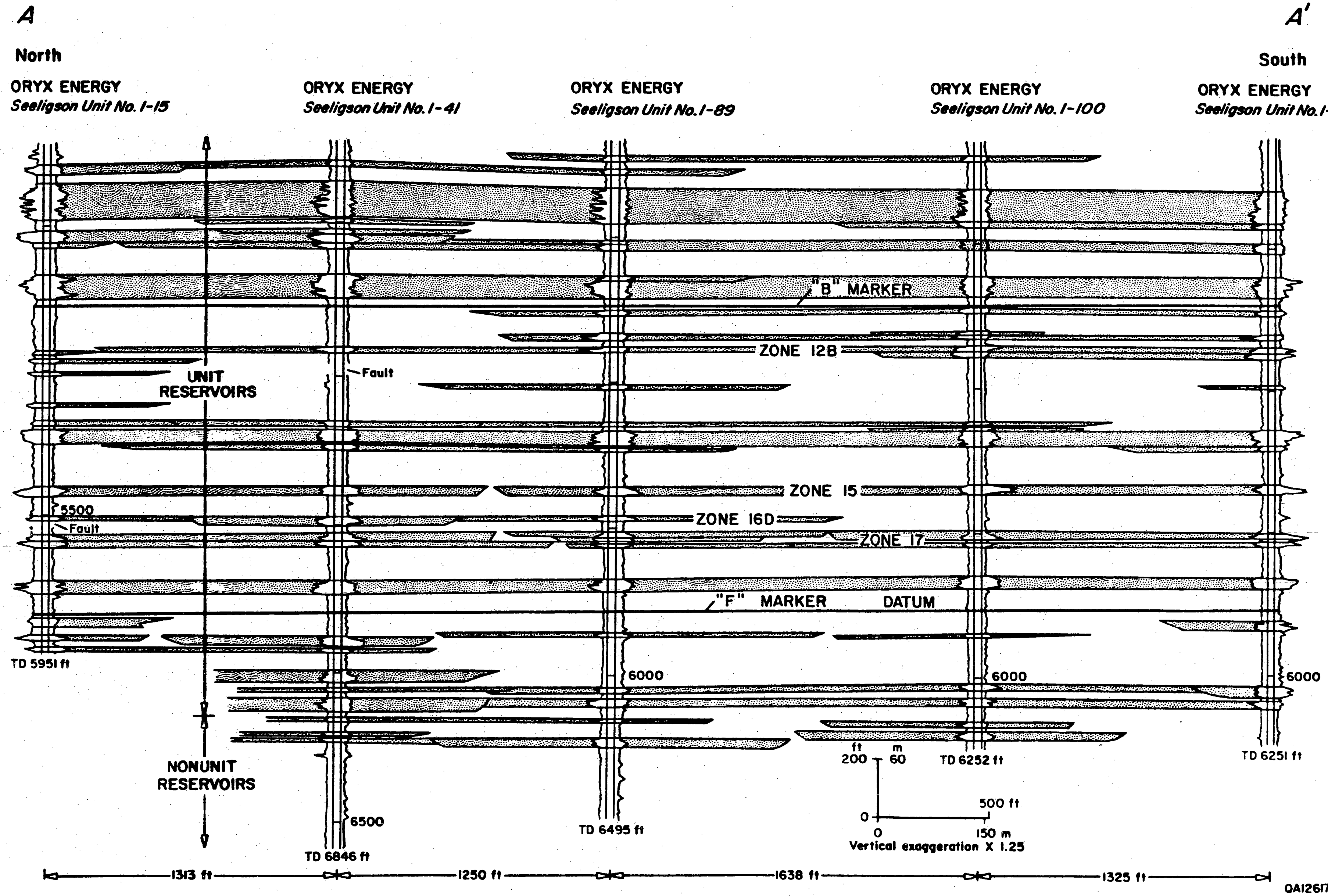

Figure 21. Stratigraphic cross section A-A' through central part of Tract 1. Multilateral and vertically stacked reservoirs are characteristic of the South Texas middle Frio. Zones 12B, 15, 16D, 16E, and 17 were studied.

reservoirs in the field. Reservoirs shallower than but including Zone 20C-44, which generally lie at depths of about 4,000 to 6,200 ft and form part of the lower and middle parts of the Frio Formation, are unitized. Nonunit reservoirs are lower Frio and Vicksburg sandstones below Zone 20C-44 (fig. 21). Fault displacements in unit sandstones are generally minor, ranging from 10 to 100 ft. However, in deeper, nonunit sandstones, faulting displaces sandstones as much as several hundred feet.

Nonunit reservoirs extend from below Frio Zone 20C-44 reservoir to at least the base of the upper Vicksburg sandstones (fig. 21). The depth of the nonunit section ranges from 6,200 ft to greater than 8,000 ft as a result of faulting. The nonunit section is divided into the upper Vicksburg sandstones and the unconformable, overlying lower Frio. Upper Vicksburg sandstones are 50- to 150-ft-thick progradational packages typically separated by 50- to 100-ft-thick mudstone sections. The thickness and overall log character is fairly consistent within the area of interest so that individual packages are readily correlated. The lower Frio contains generally laterally continuous, intercalated 10- to 50-ft-thick sandstones and 25- to 150-ft-thick mudstones. The unconformity separating the upper Vicksburg sandstones from the lower Frio is identified in the dipmeter log of the Mobil A. A. Seeligson No. 247 well, in the change in resistivity and density log character, in the seismic profile, and in correlations on well log cross sections.

Structure of the nonunit interval is complex and related to the Vicksburg growth-fault zone. Below the unconformity, large vertical separation of upper Vicksburg sandstone packages is apparent in dip-oriented cross sections as well as in the seismic profile. The northeast-southwest strike of the faults is approximately parallel to the main segment of the regional Vicksburg growth fault, which breaks the top of the nonunit section just northwest of Tract 1. Restoration of lower Frio throw across these faults indicates that movement occurred before Frio deposition. Restoration also shows that the upper Vicksburg sandstone packages are truncated below the unconformity. Down-to-the-basin faults were reactivated after lower Frio deposition, but ceased shortly thereafter because unit reservoirs are much less affected by faulting.

Unit Reservoirs Studied

Studies of Zones 12B, 15, 16, and 17 were undertaken. Analysis of Zone 19 will be conducted in research year 2.

Zone 12B. Zone 12B lies at depths ranging from approximately 4,700 to 5,000 ft in the Tract 1 area. Detailed electric log correlations reveal that Zone 12B can be subdivided into at least four genetic component sandstones. For purposes of this study, the unit was subdivided into two units, the 12B upper and the 12B lower. A grid of stratigraphic cross sections was prepared to illustrate the lateral variations and between-well heterogeneity in the 12B reservoir and to assess vertical relationships between the upper and lower units. Net-sandstone maps were prepared for the aggregate 12B interval as well as for the 12B upper and 12B lower units. Structure maps were prepared at the top of 12B upper and the top of 12B lower sandstones. Log-facies maps, based on characteristic SP-log curve shapes, were prepared for each subunit. Depositional environments and facies tracts were inferred by combining net-sandstone isopachs, log-facies maps, detailed cross sections, and erosional surface maps.

Zone 12B sandstones are widespread through Tract 1. Net-sandstone isopach maps of both 12B upper (fig. 22) and 12B lower units illustrate a predominantly east-west-trending sand-rich belt more than 1 mi wide containing localized dip-oriented net-sandstone thicks. Zone 12B sandstones shale out to the north approximately two-thirds of the way through Tract 1. Upward-fining and blocky patterns dominate in a semiarcuate trend through the area, suggesting point-bar and sandy channel-fill facies. Upward-coarsening patterns flank and transect the channel-fill facies, indicating crevasse splay and splay channel facies. Marginal to the channels are spiky and serrate log curve shapes, suggesting natural levee and overbank deposits. Baseline SP response, indicative of floodplain muds, occurs over a widespread area in

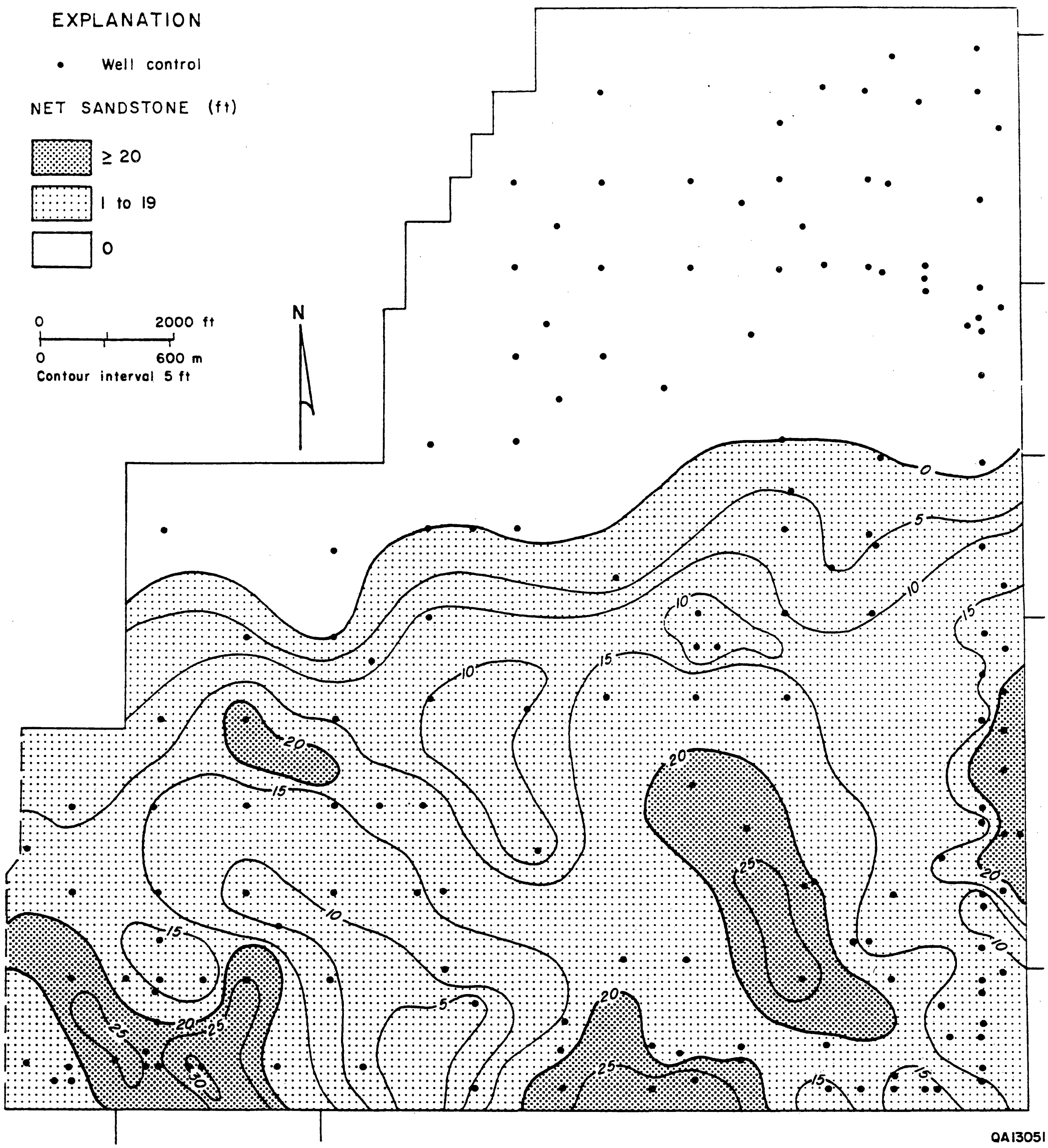

Figure 22. Net-sandstone map, Zone 12B upper, Tract 1, Seeligson field.

the north third of Tract 1. The bulk of the facies identified in both 12B upper and 12B lower units are point bar and sandy channel fill, containing rare splay channels and splay deposits. Aggradation rates were probably slow during the deposition of 12B sands, and feeder channels swept across the Tract 1 area depositing a series of multilateral point bars.

Cumulative gas production from Zone 12B from five wells in Tract 1 exceeds 77 Bcf, well 1-10 accounting for more than 59 Bcf. Production volumes cannot be disaggregated to correlate with the subdivisions of Zone 12B because both stratigraphic intervals are frequently perforated in a single completion.

The potential for isolated reservoir compartments or bypassed gas zones from 12B sandstones in the Tract 1 area is moderate to low. Although Zone 12B contains several genetic units, the absence of significant, continuous shale beds between the sandstones lowers the probability of an effective vertical permeability barrier. Lateral permeability barriers between deposits may not be great enough to restrict the flow of gas and form compartments. Production and completion practices in Zone 12B commonly perforate the entire interval, decreasing the potential for finding undrained compartments in the study area.

Zone 15. The middle Frio Zone 15 lies at depths ranging from 5,100 to 5,300 ft in Tract 1. Detailed SP and resistivity correlations reveal that Zone 15 can be subdivided into at least four genetic sandstones that are informally named 15-A through 15-D. The most common stratigraphic occurrence of Zone 15 sandstones in the study area is a two-part sandstone body, 15-B and 15-C. In Tract 1, 15-B and 15-C are coalesced into an aggregate sandstone unit; the thin shale bed that separates them farther south is generally absent.

Net-sandstone isopach maps and SP-log-facies maps were prepared for both 15-B and 15-C sandstones in the Tract 1 area. Maps and cross sections developed during previous studies of Zone 15 were used for the south part of the study area and were integrated with new maps and sections constructed in the north area to cover Tract 1 completely.

Distribution of 15-B sandstones in Tract 1 is predominantly dip oriented in a strong north-south direction. Channel-fill and point-bar facies, flanked laterally by overbank splays and levee deposits, are scattered through the study area in a general north-south direction.

Areal distribution of 15-C sandstones in Tract 1 is predominantly dip oriented. The sandstone pinches out to the west into a broad floodplain. SP-log-facies interpretations echo those for the 15-B sandstone.

Cumulative gas production of Zone 15 from 17 wells in Tract 1 is approximately 165 Bcf. Four wells (1-224, 1-225, 1-16, and 1-63) account for more than 145 Bcf of the production.

Preliminary evaluation suggests that the potential for encountering undrained compartments in Zone 15 in Tract 1 is only moderate to low. Because the separate genetic components of the reservoir amalgamate into essentially a single unit throughout most of the area, and because significant volumes of gas have been produced from fairly evenly spaced wells, the probability of identifying isolated compartments or bypassed gas zones is lessened.

Zones 16D and 16E. Zones 16D and 16E are found at depths ranging from 5,200 ft to 5,600 ft in Tract 1. Sixteen stratigraphic cross sections were constructed across the study area to establish correlations and lateral relationships of the 16D and 16E intervals. Detailed log correlations identified three channel systems within Zone 16D. Zone 16E comprises two channel systems. Net-sandstone isopach, log-facies, and erosional contour maps were prepared to establish sandstone thickness, lateral extent, and variability.

The channel systems identified in Zone 16D each display a southwest-northeast trend parallel to regional strike. In general, each system consists of channel-fill facies that gradually thin into overbank sandstones. Lateral continuity is greatest between each channel system in the southwest section of Tract 1 where channel and overbank sandstones appear to merge. To the northeast, the systems become separated by increasing amounts of floodplain deposits. Lateral continuity between systems may also be poor due to abandoned channel-fill deposits along the margins of each system.

Net-sandstone isopach maps and SP-log-facies maps suggest a different pattern for deposition of Zone 16E. Two narrow, discrete, sinuous channel systems lie in the north and southeast sections of Tract 1, separated by large expanses of floodplain muds. Log-facies maps indicate that the majority of the sandstones are channel-fill deposits that average 1,000 ft in width and 10 ft in thickness.

Cumulative gas production from Zone 16D in sixteen wells in Tract 1 totals more than 17 Bcf. Cumulative production from Zone 16E in Tract 1 wells is moderate, totaling 2 Bcf. Development and completion practices are currently being evaluated, as is the potential for bypassed and compartmentalized gas zones in these reservoirs.

Zone 17. Zone 17 is a composite sandstone widely distributed across Seeligson field. Typical aggregate sandstone thickness is 50 ft, although variations from 60 to 15 ft are locally present. In Tract 1, the base of the Zone 17 sandstone is between 25 and 45 ft above the "E" marker, a fieldwide resistivity marker. The mudstone separating Zone 17 from the overlying Zone 16E is 30 to 40 ft thick; 60 ft thick where Zone 16E is absent and Zone 16D is present.

Zone 17 contains as many as 11 genetic intervals. Each interval is identified by the highest stratigraphic occurrence of its channel-fill deposits (referenced to the "E" marker) and by crosscutting relationships with other genetic intervals. Each interval contains a set of contemporaneous facies deposited in response to a meandering fluvial system. Avulsion occurred west of Tract 1. Overall the channel segments migrated from south to north in Tract 1, and thus the channel and splay sandstones of Zone 17 at the north end of Tract 1 are stratigraphically higher and younger than those at the south end.

Production from Zone 17 in Tract 1 began in 1950, and as of April 1989, seven wells were producing gas from the reservoir. The total gas yield has been 68 Bcf. Although Zone 17 is commonly considered to be a single reservoir, completions have been made in the different genetic intervals identified in this study. The geologic assessment suggests that "leaky" barriers may be present that have the potential for undrained acreage, but that untapped compartments are not likely to be present within Tract 1.

Comparison of Reservoir Stratigraphy of Seeligson and Stratton-Agua Dulce Fields

The regional stratigraphic framework of the Oligocene Frio and upper Vicksburg Formations was established through a cross-section network totaling 71 mi in length. Strike-oriented cross sections cover a total distance of 54 mi and dip-oriented sections cover 17 mi. A single 14.4-mi-long, strike-oriented cross section extends from Seeligson field (Jim Wells and Kleberg Counties) through Monte Negro and Borregas fields (Kleberg County) to Stratton-Agua Dulce fields (Jim Wells, Kleberg and Nueces Counties). In Seeligson field, two strike-oriented and four dip-oriented sections were constructed, and in Stratton-Agua Dulce three strike-oriented and three dip-oriented sections were constructed. The well spacing along each section typically is 1,000-2,000 ft and in the areas between fields the wells are no more than 4,000 ft apart. All sections are referenced to resistivity datums in the mudstone overlying the Frio. Four stratigraphic intervals were delineated in the Frio and upper Vicksburg Formations: the upper, middle, and lower Frio, and the upper Vicksburg.

Contrasting styles of facies architecture characterize the fluvial-dominated middle Frio in Seeligson and Stratton-Agua Dulce fields. In Seeligson field, the architectural style changes vertically at least ten times over the 2,000 ft of the middle Frio, from one of laterally stacked composite fluvial systems to one of vertically stacked, more isolated fluvial systems. This change creates the distinctly stratified nature of the reservoir zones in Seeligson field. In Stratton-Agua Dulce fields, by contrast, the architectural style is one of vertically stacked fluvial systems leaving clusters of channel-fill and splay sandstone reservoirs surrounded by nonreservoir, floodplain mudstones. In addition, the upper 500 ft, and to a lesser extent the lower 100 ft, of the 2,500-ft-thick middle Frio at Stratton-Agua Dulce is composed of the laterally stacked architecture characteristic of the Seeligson field.

Heterogeneity of laterally stacked systems will likely produce leaky barriers to gas flow, whereas heterogeneity of vertically stacked systems will likely produce effective gas barriers resulting in the high potential for undrained compartments (fig. 23). Thus, the architecture of the Stratton-Agua Dulce sandstones may be more favorable for unrecovered natural gas than the architecture of the Seeligson field sandstones. This observation remains to be confirmed through field-data collection and access to operator data at Stratton-Agua Dulce.

FIELD-DATA ACQUISITION, SEELIGSON FIELD

Programs were prepared to collect whole core and sidewall cores, formation-pressure test data, open- and cased-hole logs, and VSP's in the Mobil A. A. Seeligson Nos. 247 and 248 wells, which are nonunit, deeper-pool tests drilled by Mobil Exploration and Producing U.S., Inc., in Tract 1 of the A. A. Seeligson lease (fig. 20). The program was designed using well logs, well-bore sketches, well-history summaries, base maps, and production and engineering data that we collected for wells in Tract 1 at Oryx Energy Company's and Mobil's offices. Mobil also provided a dip-oriented seismic section through the location of the Mobil Seeligson No. 247 well, a parallel dip section through the location of the Mobil Seeligson No. 248 well, and a strike line tying the dip section. Field tapes and support data for enhanced processing were also provided.

Objectives

The program of whole cores and sidewall cores from the Mobil A. A. Seeligson Nos. 247 and 248 wells was designed to help the study of depositional environment and diagenesis and the calibration of well logs. The VSP surveys aim at the identification of interwell facies variations in Frio unit sandstones and, in the 247 well, in nonunitized Frio and Vicksburg deeper-pool reservoirs. The program of formation-pressure tests (PT) in unit and nonunit reservoirs in both wells aimed at the assessment of pressure communication or permeability barriers in equivalent zones in nearby, relatively closely spaced wells. Cased-hole logs were

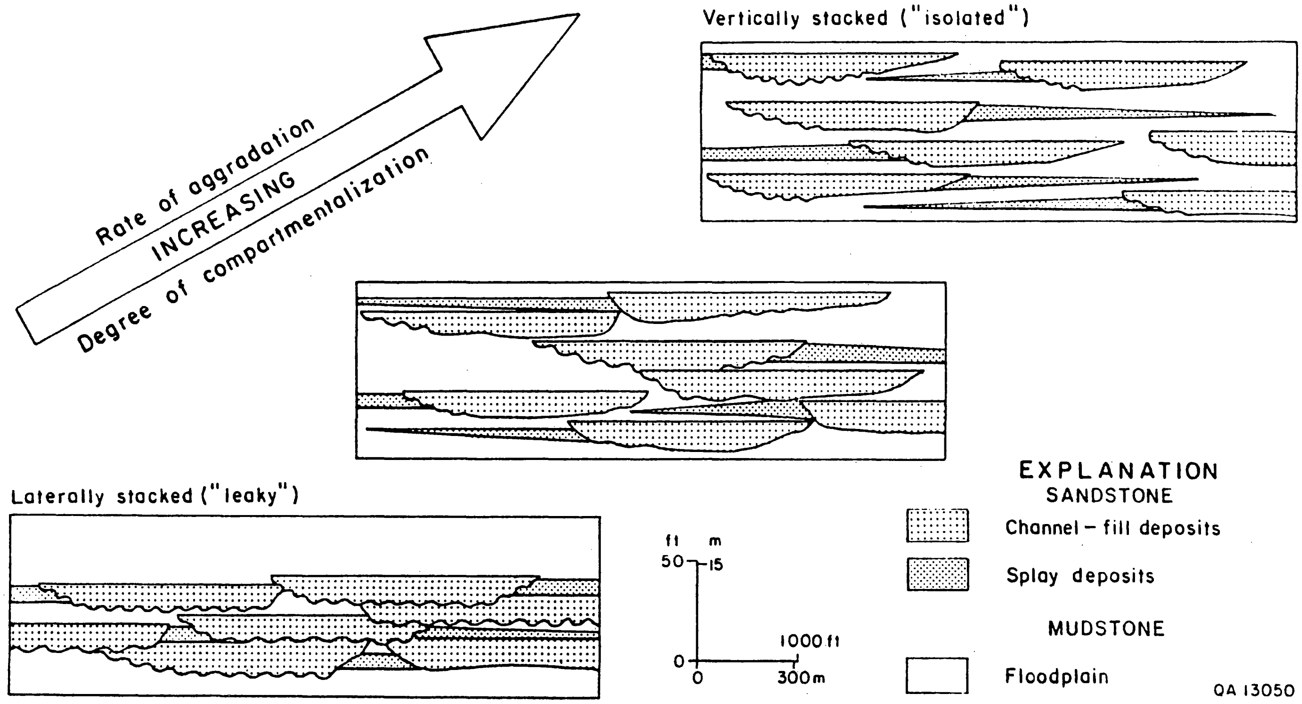

Figure 23. Fluvial facies architecture and reservoir heterogeneity.

programmed to aid in the evaluation of bypassed gas. Porosity, water saturation, and lithology can be determined by processing measurements from logs recorded previously, particularly porosity logs, using newly acquired cased-hole measurements. Integrating these efforts with petrophysical, geological, and engineering data can result in the identification and exploitation of bypassed gas.

Petrophysical problems encountered in Seeligson field are similar to those found in other shaly sandstone reservoirs. High surface area clays line the pores of sandstones causing high immobile water saturation. In addition, shales contain significant amounts of effective porosity that may mask shaly pay intervals if not accounted for. Appendix B summarizes research conducted by ResTech on shale porosity. Illustrations of the effects of these problems are shown on the induction log of the Mobil A. A. Seeligson No. 247 well (fig. 24). The low-resistivity pay sandstone found from 7,305 to 7,397 ft was perforated from 7,308 to 7,332 ft and produced at a rate of 1.618 MMcfpd. Compounding the identification of this pay zone are the results of sequential formation-pressure tests. Low pressures (fig. 24, next to the depth track) are believed to be not the result of partial pressure depletion but the reflection of inconclusive tests.

Field Operations

Following establishment of an agreed program of data acquisition in the Mobil A. A. Seeligson wells Nos. 247 and 248, a formal contractual relationship was established to define liabilities, rights, and obligations of Mobil Exploration and Producing U.S., Inc., and the SGR project. The simplified premise of the contractual relationship was that Envirocorp would purchase from Mobil, for BEG as Lead Technical Contractor, certain log, core, pressure-test, and seismic data. Envirocorp and other project participants consulted with Mobil in planning and organizing the data collection but the collection itself was Mobil's responsibility. In this way, Mobil retained control over, and responsibility for, all activity at the wellsite. The contract also

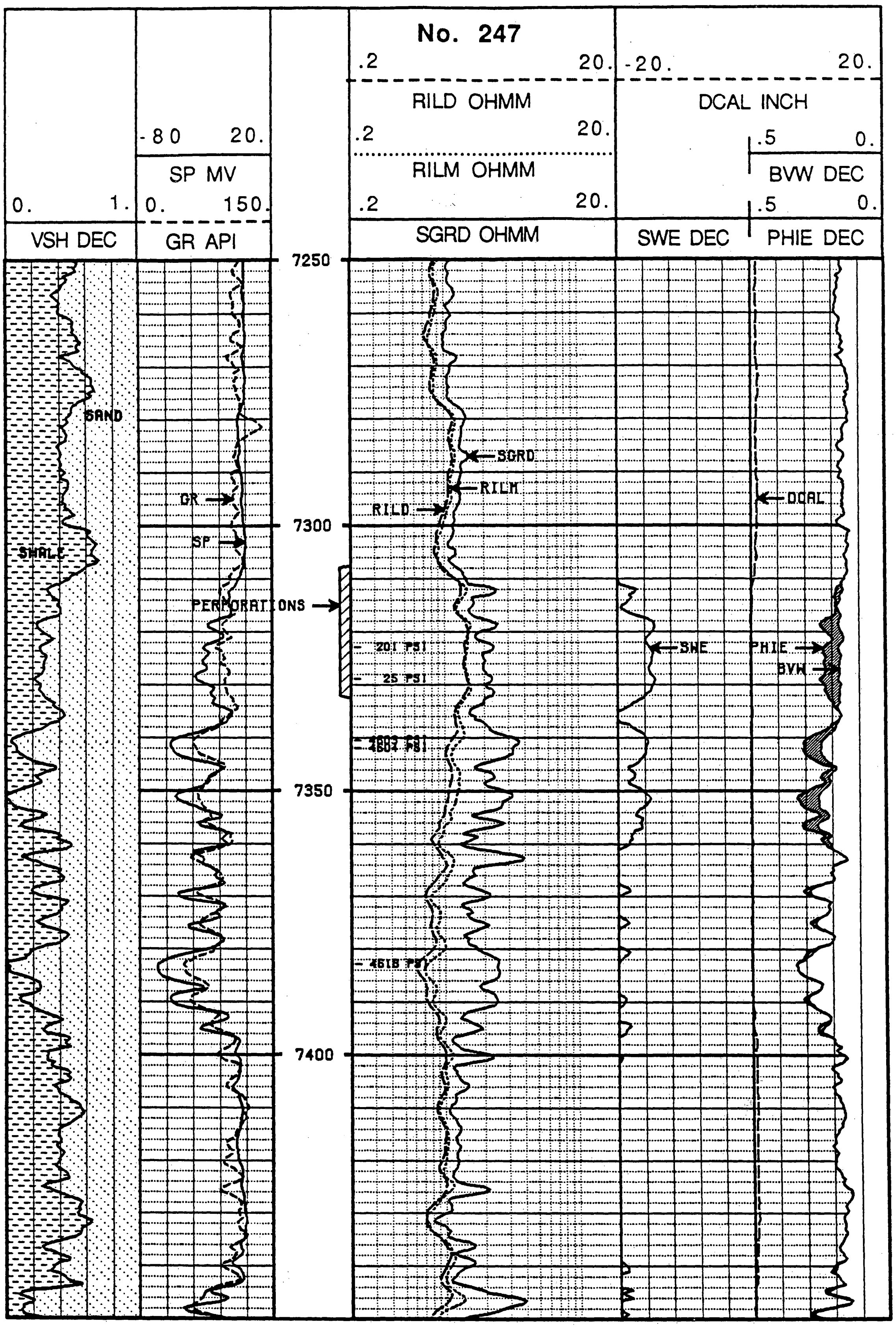

Figure 24. Induction log from the pay interval of Mobil Seeligson No. 247 well. Calculated lithology, porosity, and water saturation also shown.

established invoicing and reimbursement procedures between Mobil and Envirocorp. The actual specification of data to be collected and costs to be reimbursed was accomplished through a series of purchase orders. Envirocorp was to coordinate and facilitate the actual data collection process at the well site; BEG, ResTech, and Envirocorp staff were at the well sites during actual data collection. Table 4 summarizes the results of the programs.

The program was reduced somewhat from the original plan because severe problems of lost circulation precluded acquisition of some of the open-hole logs, sequential pressure tests, and sidewall cores in well No. 247. The lost opportunity to acquire pressure data in two wells spaced approximately 3,700 ft apart, and thereby to evaluate pressure continuity, was a significant loss to the SGR program. This in turn eliminated the desirability of cased-hole logs and the necessity for two planned wiper trips. The remaining costs were nonetheless below those anticipated because vertical seismic profile data were obtained at a cost less than originally estimated.

Mobil contributed to this program by providing 63 hours of rig time and additional completion-unit and mast-truck time. Mobil also contributed to the cost of other data and released proprietary information to the project, including the standard log suite, two dipmeter runs, and a basic suite of sidewall cores and sequential pressure tests.

Cores and Open-Hole Logs

The coring and logging program designed for the Mobil Seeligson Nos. 247 and 248 wells comprises (1) dual-induction resistivity, (2) formation-density, (3) compensated-neutron, (4) gamma-ray, (5) full-wave acoustic, (6) dipmeter, (7) sequential formation-pressure tests, and (8) sidewall cores.

Table 5 shows the logs obtained in the two cooperative wells across the unitized section. Several logs originally in the acquisition plan in the Mobil No. 247 well were cancelled due to adverse hole conditions.

Table 4. Types and costs of data acquired, cooperative wells, Seeligson field.

Data	Planned cost ($)	Actual cost ($)
Open-hole Logs	$ 50,000.00	$ 31,900.00
Sequential Formation Pressure Tests	15,200.00	6,300.00
Percussion Sidewall Cores	6,000.00	2,700.00
Cased-hole Logs	17,100.00	10,900.00
Vertical Seismic Profiles	175,300.00	140,200.00
Total	$263,600.00	$192,000.00

Table 5. Cores and open-hole logs acquired by SGR project, cooperative wells, Seeligson field.

Log name	Seeligson No. 247 well	Seeligson No. 248 well
Dual induction	X	X
Full-wave acoustic	X	
Borehole-compensated sonic	X	
Formation-density	X	X
Compensated-neutron	X	X
Gamma-ray	X	X
Sequential pressure tests		X
Dipmeter		X
Sidewall cores		X

Problems Encountered

Problems were encountered in the acquisition of open-hole logs in the two cooperative wells. The problems are primarily associated with the recording of the full-wave acoustic log and the execution of sequential formation-pressure tests.

Figure 25 illustrates the problem encountered with the full-wave acoustic log. Whereas the instrument is able to obtain high quality values for compressional velocity, it is virtually unable to distinguish shear velocity from the arriving tube or mud waves. To solve this problem, a shear source must be used. Mobil is currently the only organization that has this type of tool; it is not available on a commercial basis. Both Schlumberger and Halliburton, however, are in the development stages of making a commercial device. The problem described here is common to all low-velocity Gulf Coast shallow sequences. Longer transmitter-to-receiver spacing has been tried but has not been successful.

Problems were also encountered during acquisition of sequential formation-pressure data. In low-permeability, shaly sandstones, the time necessary to obtain valid shut-in pressures using the tool may be prohibitive. However, a significant number of tests can be salvaged by knowing whether the tool has been set in a low-permeability, restricted-flow zone, or in a partially depleted zone. Many times, a few minutes more of set time is all that is necessary for the tool-indicated pressure to build up to formation pressure. In the Mobil No. 247 well, a low-resistivity, high-water-saturation, pay sandstone was completed from 7,308 to 7,332 ft. The formation-pressure-test data across the zone indicated the zone to have 201 psi formation pressure. Production tests after perforations now indicate the zone has a formation pressure of 4,300 psi. Two sequential pressure tests taken just below this zone at 7,341 ft and 7,342 ft indicate more than 4,600 psi formation pressure. The higher pressure is obviously the correct one for the completed zone. Figures 26 and 27 are the field recordings of the two tests taken. One test at 7,323 ft indicates 201 psi; the other test at 7,341 ft indicates 4,603 psi. The test at

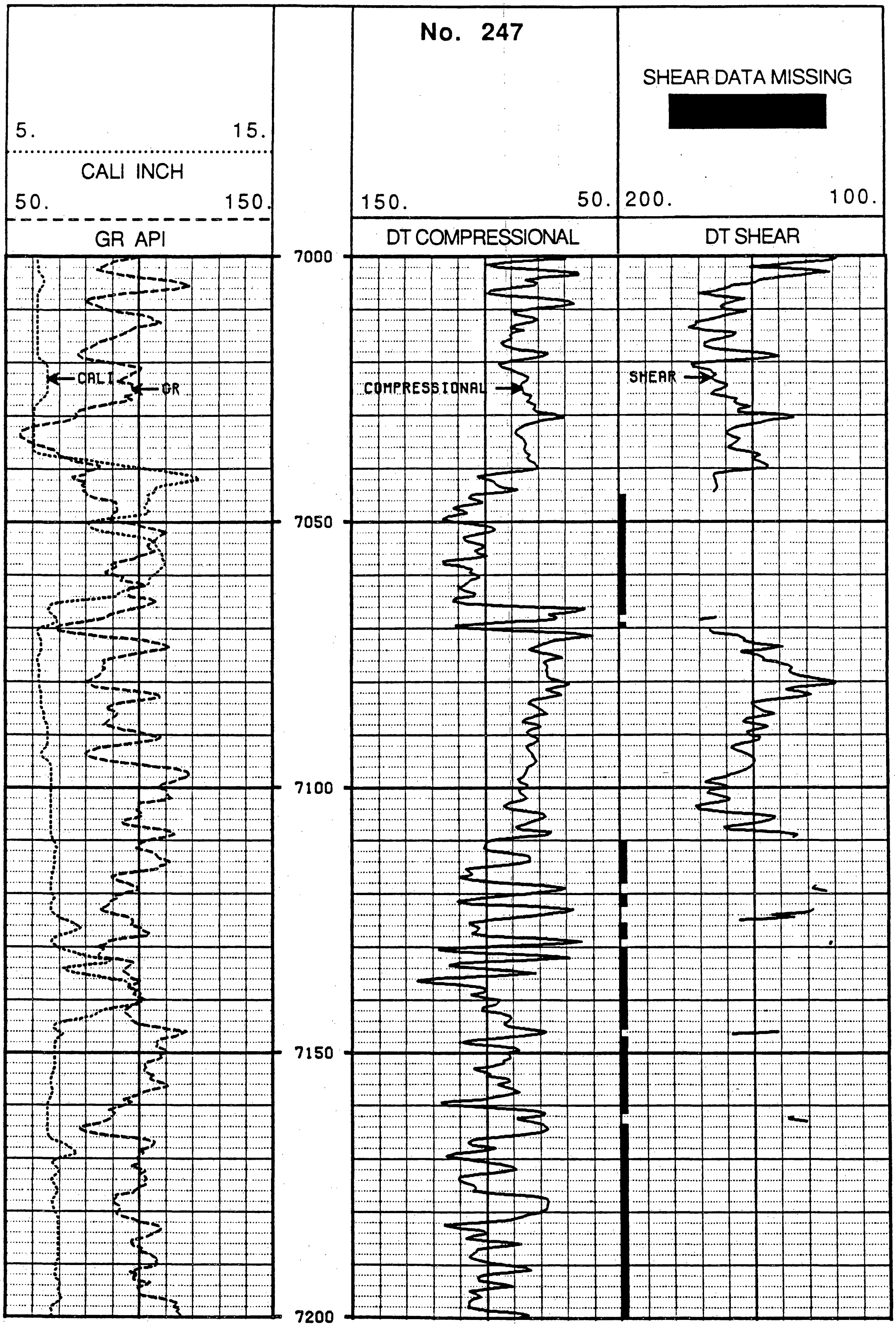

Figure 25. Full-waveform sonic log of Mobil Seeligson No. 247 well.

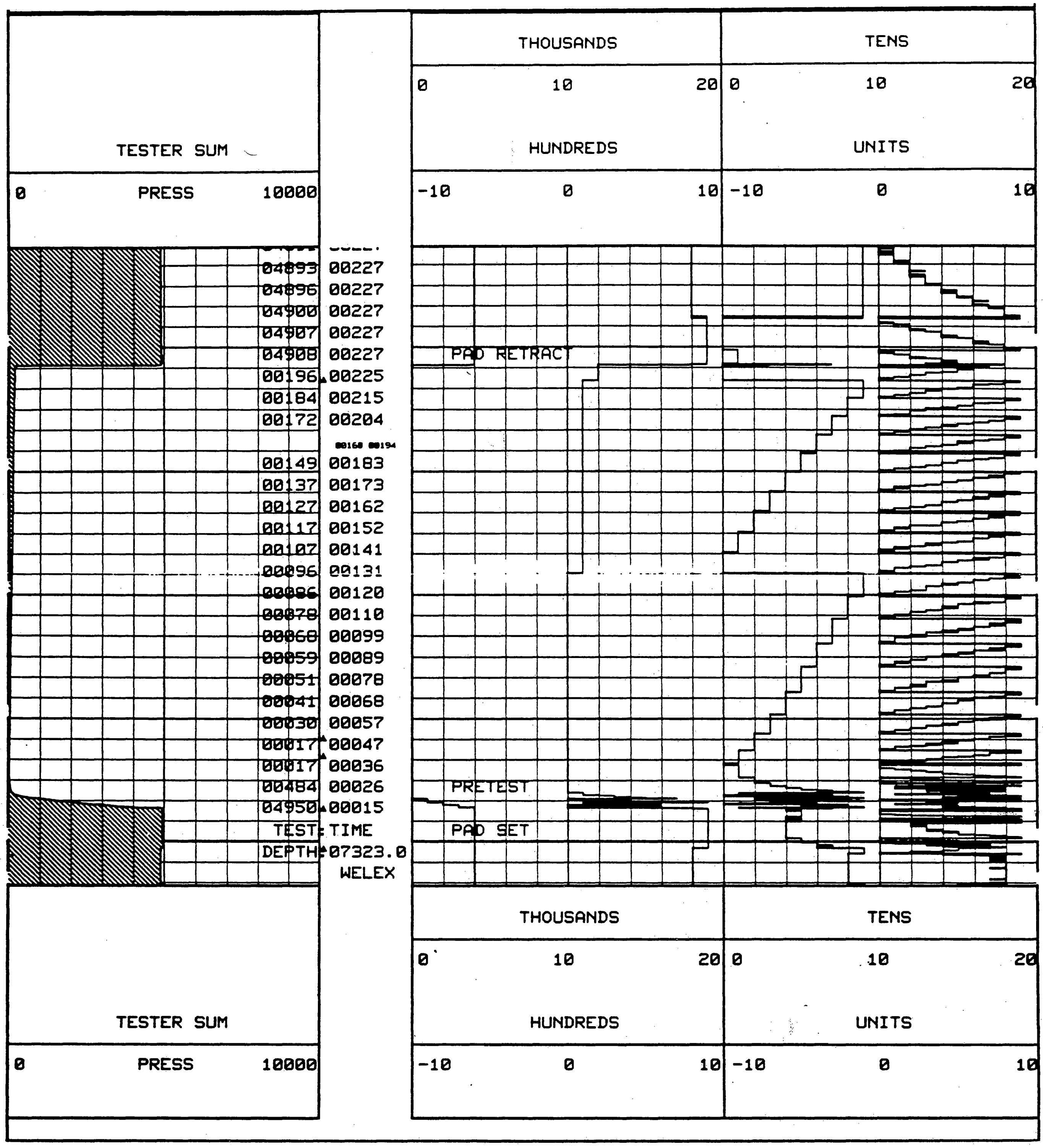

Figure 26. Formation-pressure test taken at 7,323 ft. Pressure builds up to 201 psi immediately before tool is retracted. The test was prematurely terminated.

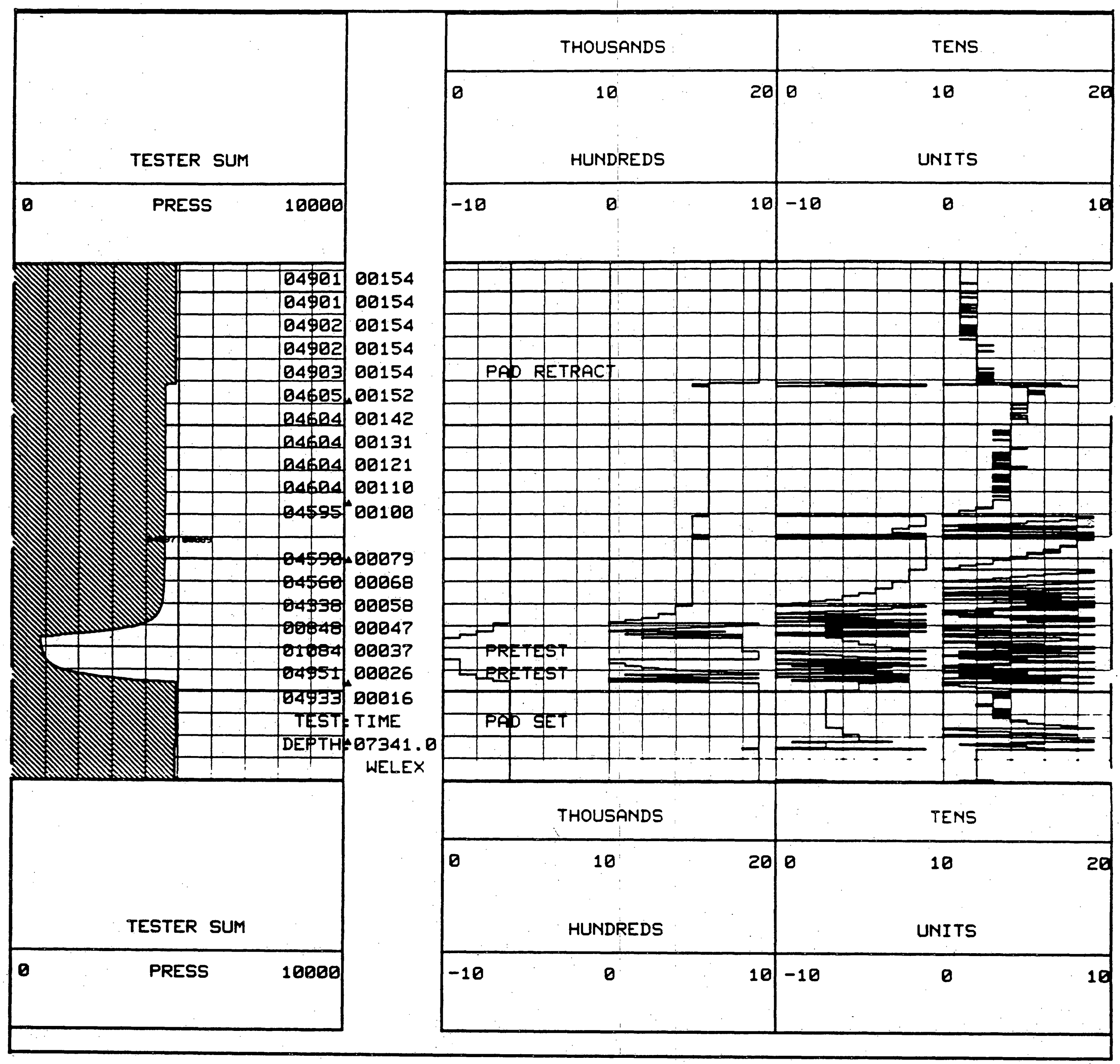

Figure 27. Formation-pressure test taken at 7,341 ft. Pressure builds up to 4,603 psi within 110 seconds of setting the tool.

7,341 ft built up rapidly to 4,603 psi. The test at 7,323 ft was in the process of building up slowly when it was terminated. Failure to identify the fact that this test was prematurely terminated could result in the zone not being completed. In the Mobil No. 248 well, forty pressures were taken and assumed to be valid by the engineers in the field. After careful examination, twenty of these tests were found to be prematurely terminated. Only twenty tests were valid. The successfully completed zone in the Mobil No. 247 well produced on a production test 1.618 MMcfgd on 9/64-inch choke. It is obvious that the problems associated with formation testing need to be addressed.

Several solutions are viable. One solution is to modify the tool mechanically to increase the speed at which pretest chambers in the formation-pressure tool fill (necessary for formation pressure). This can be accomplished by decreasing the size of the pretest chamber or by increasing the surface area of the sampling port. Both techniques improve the efficiency of the pressure test allowing a faster buildup in low-permeability formations. A thorough knowledge of the capabilities of each service company is necessary for a successful testing job. In the future, all service companies running tests for SGR will be contacted to alert them to the problem.

Another possible solution is the extrapolation of sequential formation-pressure buildup data to determine formation pressure. When a test is terminated, the pressure has not built up long enough to determine true formation pressure. With proper modeling of the test tool, the reservoir geometry, and the after-flow and buildup pressure behavior, it may be possible to estimate formation pressure. If this can be accomplished, many tests can be interpreted by extrapolating the buildup pressures to formation pressure with acceptable accuracy. REC and ResTech are jointly pursuing solutions to this problem.

Cased-Hole Logs

The cased-hole logging program aimed at support necessary for VSP acquisition and for research to determine formation pressure behind pipe using count rates from the pulsed-neutron log. The cased-hole logging program in the Mobil No. 247 well was abbreviated because the sequential formation-pressure tests were not run across unit sandstones (because of mechanical problems in the well bore). Temperature and noise logs were run in the Mobil No. 248 well because of acquisition problems associated with the VSP. Table 6 shows the cased-hole logs obtained on the two cooperative wells.

In older fields, where significant differences in pressures may occur between sandstones, poor casing cementing may be a problem. It was locally difficult to isolate productive sandstones from one another in both the Seeligson Nos. 247 and 248 wells. This difficulty resulted in what appears to be (on the Seeligson No. 248 noise and temperature logs) communication behind pipe. The cement-bond log run in the No. 247 well (fig. 28) illustrates a poor cement job across the sandstone from 5,610 to 5,630 ft. Amplitude and waveform analyses both indicate this zone to be poorly cemented. The temperature log (run before perforating) of the Seeligson No. 248 well from 5,000 to 6,400 ft (fig. 29) indicates expansion of gas, confirming communication between several zones. The noise log of the same well, although not indicating noise at exactly the same depths as the temperature anomalies, confirms several gas entries. This noise is significant enough to cause problems with the VSP. Mobil conducted remedial cement squeezing on both the Seeligson Nos. 247 and 248 wells to control the apparent communication behind pipe.

Thermal Decay Time (TDT) or pulsed-neutron logs have been used successfully elsewhere in Seeligson field to identify recompletion candidates. Pulsed-neutron logs integrated with cased-hole sonic data are used to determine porosity and water saturations and to provide a good qualitative gas indicator. Furthermore, project studies are under way to assess the relations

Table 6. Cased-hole logs acquired by SGR project, cooperative wells, Seeligson field.

Log name	Seeligson No. 248 well	Seeligson No. 247 well
Cement bond	X	X
Temperature	X	
Noise	X	
Thermal decay time (Pulsed-neutron)	X	

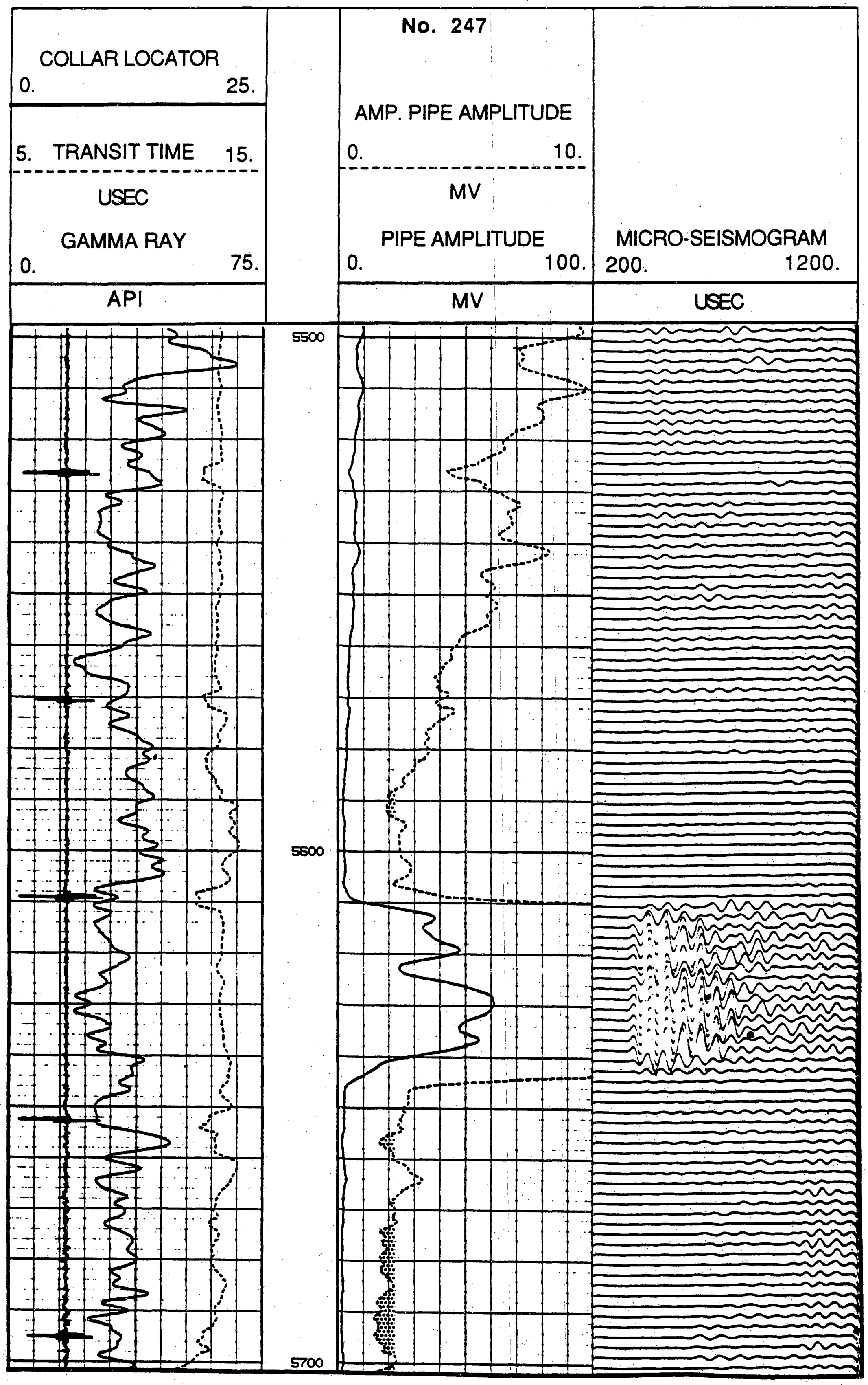

Figure 28. Cement-bond log taken in Mobil Seeligson No. 247 well. Notice the poorly cemented zone at 5,610–6,630 ft where casing arrivals are present and amplitude is high.

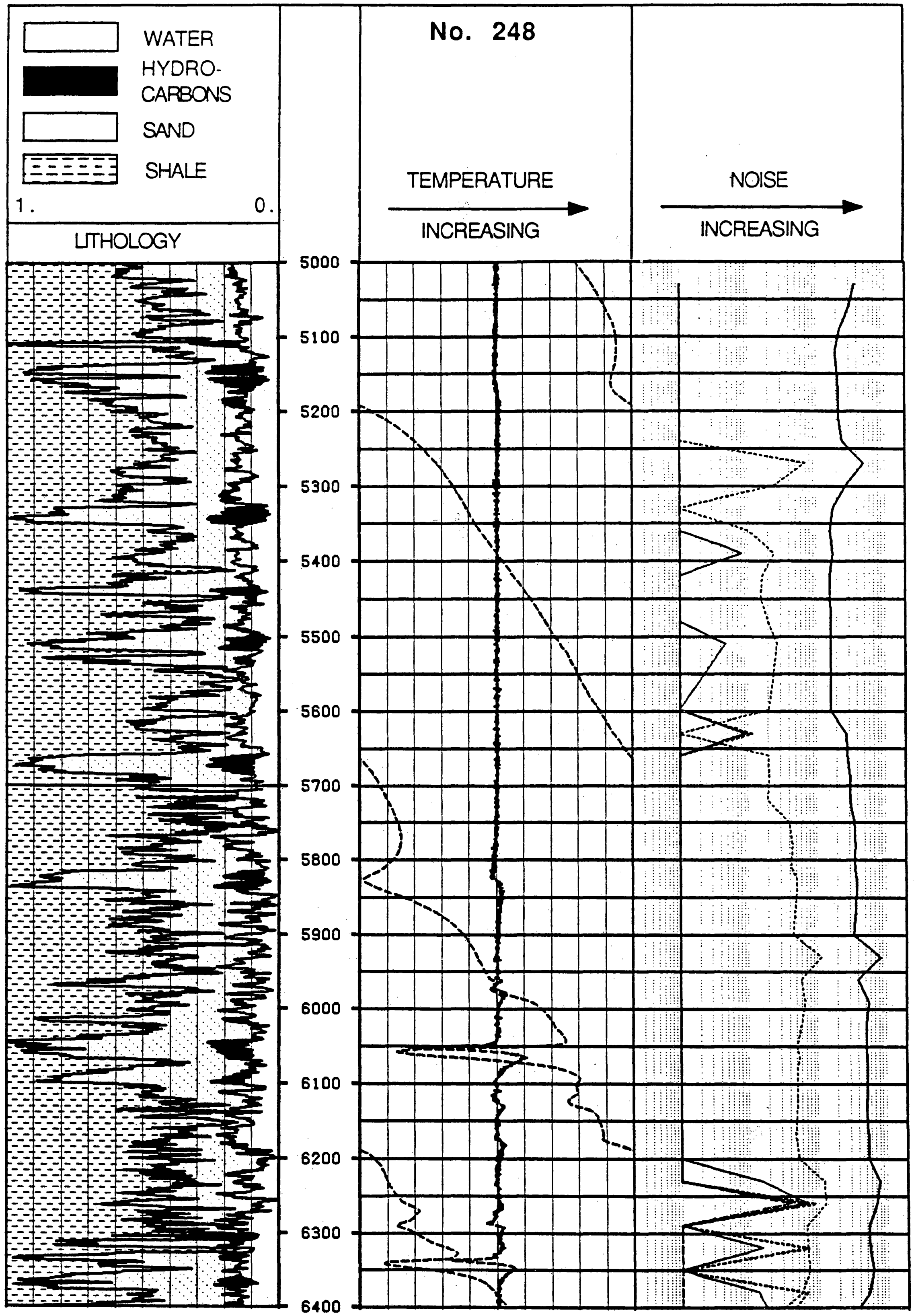

Figure 29. Noise and temperature logs in Mobil Seeligson No. 248 well. Communication between sandstones is common in poorly cemented wells having zones of significant pressure differences.

between TDT log response, gas saturation, and reservoir pressures. Sandstone zones having good saturations but low reservoir pressures were found in the Seeligson No. 248 well. The ratio of the near and far count rates from Schlumberger's TDT-P log was correlated versus valid pressure readings from the sequential pressure tests (fig. 30). This technique holds some promise if the gas saturation is known. Figure 30 identifies the fair correlation; however, different gas saturations may cause some differences in the near-to-far count ratios when zones are at similar pressure. The problem of deriving pressure through casing is serious and will be pursued further. The next step will be to identify the effect pressure has on other devices such as the through-casing, full-wave acoustic log.

Vertical Seismic Profiles

A multioffset VSP program was designed around the Mobil A. A. Seeligson Nos. 247 and 248 wells (fig. 31). Seismic-ray-traced models for the area were developed by Earth Resources Laboratory (ERL) using 2-D seismic data and well log structural cross sections (provided by the BEG) through Seeligson field. Imaging unitized sandstones was emphasized. Modeling indicated that a laterally truncated sandstone having the dimensions of a typical Seeligson unit middle Frio sandstone could be identified on noise-free, ray-tracing synthetics.

A check-shot survey (zero-offset VSP) was recorded using 30-ft geophone levels in the upper 2,800 ft in the No. 248 well to collect detailed velocity data for the shallow section. Modeling had indicated that a high velocity contrast existed at a depth of 2,100 ft that would produce strong converted SV (vertically polarized shear) waves cutting across the data set and making interpretation of variations in reflections of truncated sandstones extremely difficult. Although there is a strong event on the surface seismic data at approximately this depth, the check shot run in the No. 248 well did not indicate a high velocity contrast, and the feasibility of the remaining program was confirmed.

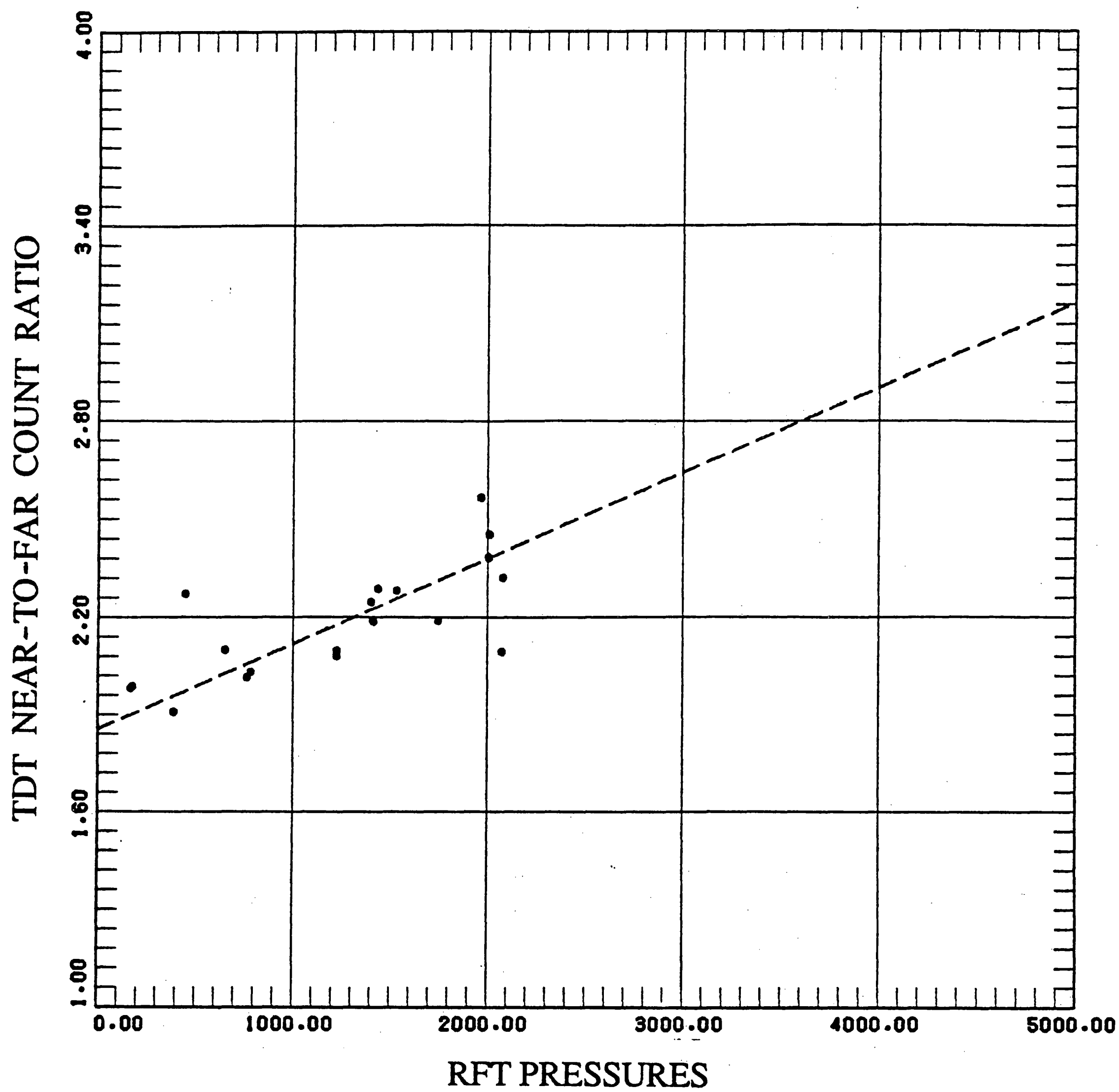

Figure 30. Relationship between pulsed-neutron and formation-pressure data in Mobil Seeligson No. 248 well.

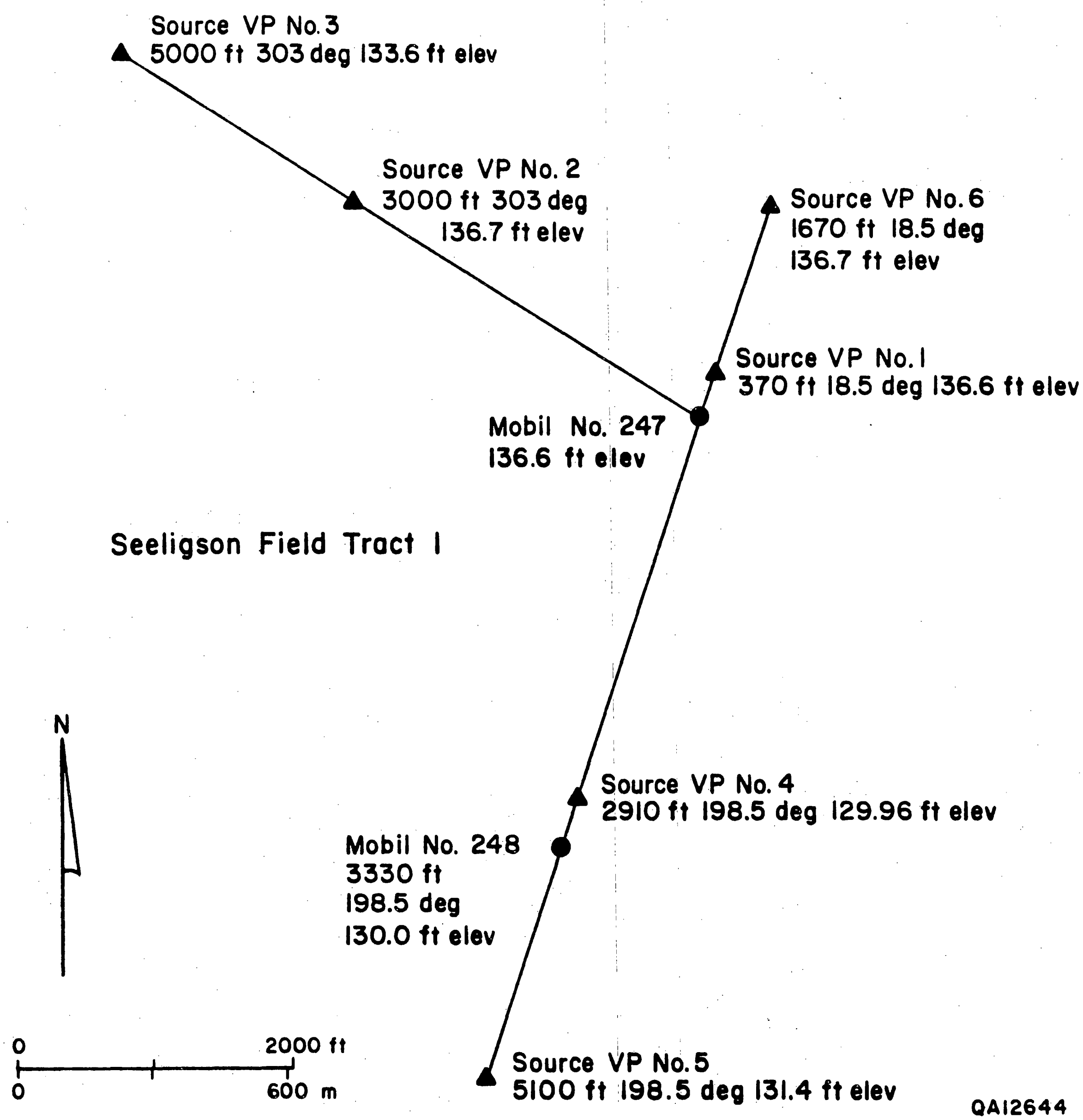

Figure 31. Index map of VSP surveys in Mobil Seeligson No. 247 and Seeligson No. 248 wells, Tract 1, Seeligson field. Distances and azimuths are measured from Mobil Seeligson No. 247 well surface location.

Four offset VSP's were acquired using a wall-coupled 3-component 8-Hz slim hole receiver downhole in the No. 247 well. A total of 198 levels were recorded in the well. A near offset was recorded with a source location 370 ft and 30 degrees northeast of the well bore over the interval from 7,630 ft to 160 ft in the well bore. One updip offset VSP was recorded at a distance of 3,000 ft in an azimuthal direction of 303 degrees from the No. 247 well bore. Two cross-well offset VSP's were also recorded, one at a distance of 2,910 ft from the well bore and the other at a distance of 5,100 ft in a 198.5-degree azimuthal direction from the No. 247 well. The 2,910-ft offset location and the zero-offset source location were reoccupied during the recording of three offset VSP's in the Mobil No. 248 well and served as the zero-offset and 3,700-ft cross-well offset, respectively, in that survey.

Field stacks of data acquired show good data quality with upgoing as well as downgoing information. Of particular interest were a series of good P-wave reflections from the unit sandstone depth interval, and P- and S-wave reflections from the Vicksburg interval below the unit and the well bore. Additionally, the ability to record good quality data in zones of apparently poor cement (as indicated by the CBL) was encouraging. VSP data requires good coupling to the formation, and sufficient time-lapse between the cement job and commencement of the VSP operation probably allowed improvement in the casing-to-formation bonding of poorly cemented casing.

Three VSP's were recorded in the Mobil Seeligson No. 248 well. Data were acquired for a zero-offset (420 ft north of the well bore), a 3,700-ft-offset in the strike direction using the same source location as the zero-offset for the No. 247 VSP, and a 5,000-ft-offset in the strike direction. Acquisition parameters and equipment were the same as those used in the No. 247 surveys. Data quality was generally good even in intervals having very poor cement bonds. Data were also locally recorded in double pipe near the surface with good coupling. Stacked raw field data were significantly noisier than those recorded in the No. 247 well, but plots still show good reflections from the unit sandstones.

Temperature and noise logs were run in the No. 248 well to address the occurrence of high-frequency noise observed during downhole acquisition of VSP data at 5,400 ft and in the 6,000–6,500-ft depth interval. Analysis by ResTech of the temperature log indicated that significant reservoir communication behind pipe, in the annulus around the casing, existed in the No. 248 well at the time of logging. Sandstones in the depth intervals 5,136–5,177 ft; 5,815–5,839 ft; 6,041–6,070 ft; and 6,331–6,338 ft exhibited temperature responses, indicating either gas entry into a channel or gas exit into a lower pressured zone at that time. A temperature anomaly at 6,290 ft was probably the result of liner overlap. Similarly, noise anomalies will occur opposite gas entries (or exits) and also at changes in channel shape. The response on the noise log also indicated gas movement, suggesting significant channeling behind pipe at the time of logging. Future strategic use of noise logs before well-bore seismic work (VSP and cross-borehole) will help to improve design and execution of such surveys.

Seismograph Service Company (SSC), which served as acquisition contractor, is also performing the basic processing on the four VSP's from No. 247 and the additional three recorded at No. 248. SSC provided standard velocity survey plots, zero-offset synthetic seismograms, and calibrated logs for correlation with seismic data and upgoing- downgoing-, and offset-vertical stacks. Additional enhanced processing and inversion will be undertaken as interpretation and integration with other data proceeds.

Additional Data-Acquisition Plans, Seeligson Field

A second cooperative data collection plan for Seeligson field to be conducted in conjunction with Oryx Energy Company operations has been formulated. The program focuses on unitized Frio reservoirs in the vicinity of the Mobil A. A. Seeligson Nos. 247 and 248 wells where the original cooperative effort with Mobil Exploration and Producing U.S., Inc., was conducted.

Oryx has agreed to release to the project three temporarily abandoned wells (1-89, 1-85 and 1-171) (fig. 32) for use in data acquisition under this plan. Before data collection, the wells will be reentered, cleaned of any obstructions, and pressure tested. Cased-hole sonic, TDT, cement-bond, and noise and temperature logs will be run for borehole and formation evaluation, as well as to assist planning and interpretation of VSP surveys. Additional logging will potentially include use of Mobil's shear-dipole sonic tool for collection of full-waveform shear and compressional velocity data, and well deviation surveys for detailed downhole deviations necessary for correct tomographic imaging.

Mobil Research and Development Corporation and Bolt Technology have agreed to provide technical service to the project for cross-borehole tomographic studies. This cooperation is important because to date no borehole airgun has been commercially available for recording seismic data for tomographic studies at depths greater than 3,000 ft.

Cross-well seismic surveys can provide additional information for delineating and describing reservoirs. Higher resolution can be achieved in cross-well recording because (1) transmission does not occur through surface layers, which dissipate large amounts of energy, (2) noisy surface conditions are avoided, and (3) travel paths are shorter. In addition to reflection images such as those obtained using surface data, cross-well transmission images are obtained that have significantly greater signal-to-noise ratios.

Cross-well seismic surveys have been successfully employed in CO_2, fire, and steam-flood monitoring, and (to a more limited degree) in the definition of stratigraphic variations. Hardware development of both a nondestructive downhole source and a multilevel receiver array for recording a large number of travel paths in a short time has severely restricted application of cross-well seismology. To date, interpretation of stratigraphic variations and geologic framework from tomograms has been limited. The cross-borehole survey proposed at Seeligson aims at demonstrating the application of cross-well tomography for delineating the reservoirs in the interwell areas.

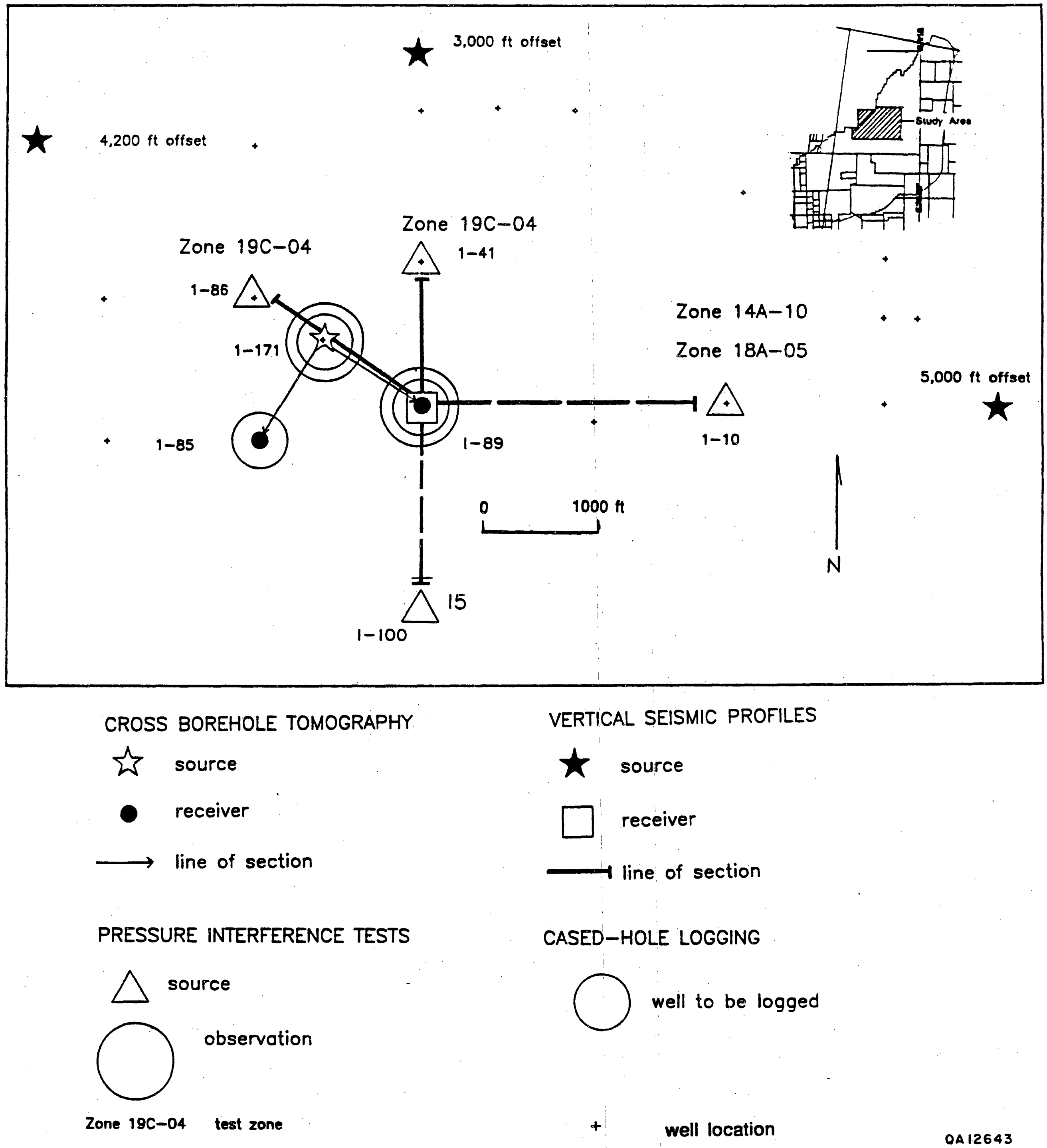

Figure 32. Index map of proposed data collection program in Tract 1, Seeligson field. Cross-borehole tomography, vertical seismic profiles, pressure interference tests, and cased-hole logs comprise the program. Wells 1-89 and 1-100 will be alternate test locations.

The tomographic survey will be conducted utilizing the 1-171 well as a source and both the 1-89 and 1-85 wells as receivers. The two tomogram legs will be 1,040 ft and 1,020 ft long, respectively (fig. 32). Cross-borehole seismic surveys using airgun sources have been recorded for various well-borehole spacings, but higher frequency energy is typically attentuated in lower velocity soft sediments such as those of the Gulf Coast. In order to achieve a desirable level of resolution for a cross-borehole survey in Seeligson field, well spacing between source and receiver should be kept less than 1,300 ft. It is expected that 400-Hz data can be recorded for these distances at the velocities in the unit sandstones. A vertical distance of 1,000 ft will be surveyed at 20-ft intervals and will include the lower unit sandstones. The zone surveyed will cover Zones 14A through 19C and is expected to provide several examples of laterally discontinuous sandstones. Mobil will also provide modeling and processing support for the tomographic work. The data will be combined with geological, VSP, and pressure-interference information for a complete, integrated assessment of between-well reservoir continuity.

An offset VSP program has been designed using the 1-89 well as a receiver location and will be integrated with pressure-interference testing. Offsets will be located approximately (1) 4,200 ft northwest of the 1-89 well to provide subsurface coverage between the 1-89 and 1-86 wells, (2) 5,000 ft east of the 1-89 well to provide coverage between the 1-89 and the 1-10 wells, and (3) 3,000 ft north of the 1-89 well to collect subsurface information between the 1-89 and the 1-41 wells (fig. 32). In addition, a zero-offset VSP will be recorded in the 1-89 well. An additional VSP may also be run through the 1-41 well using the 1-171 well as a receiver well for correlation with the interference testing. It is anticipated that the pressure interference testing will result in the determination of several reservoir discontinuities that may also be detectable with high resolution VSP data.

Pressure-interference testing will be conducted for producing Zones 19C-04, 18A-05, and 14A-10. Bottom-hole pressures will also be recorded during the shut-in period on each interference test in each well currently producing. The 19C-04 sandstone will be tested by pulsing the producing 1-86 well for a 7-day shut-in period and observing the pulse in the 1-171 and 1-89 wells. Following that test, an additional test in Zone 19C-04 will be conducted by pulsing the 1-41 producing well for a 10-day shut-in period and observing pressure data in the 1-89 and 1-171 wells. Zone 18A-05 production in the 1-10 well will be shut-in for a 14-day period and the 1-89 well will be used to record pressure. A 14-day shut-in period for Zone 14A-10 in the 1-10 well will serve as a pulse for observation in the 1-89 well (fig. 32). There were some indications at the end of research year 1 that well 1-10 may not be available. If that should be the case, a well located to the south of well 1-89 might be used to test one alternate zone.

Oryx will supply tubing and packers for the operation and will also provide flow-rate data for the producing wells during the pressure-interference testing. In addition, the Seeligson unit will defer approximately 38 MMcf of gas production from the 1-10, 1-86, and 1-41 wells during shut-in periods of the pressure-interference testing program. The entire data collection program is expected to extend over a three- to four-month period.

RESERVOIR ENGINEERING STUDIES

Production Diagnostics for Reservoir Compartmentalization

Expanding and improving techniques for using pressure and production data to infer reservoir parameters has been a primary effort in the engineering studies during the first year of the SGR project. The classical techniques of empirical evaluation of decline curves and plots of P/Z versus cumulative production have been reexamined using a new conceptual reservoir model appropriate to the compartmentalized reservoirs of the Frio and Vicksburg plays. This study has been carried out in a sequence of simulation studies.

The basic concept of the model is that a gas reservoir can be represented as a set of permeable compartments having limited pressure communication through low permeability barriers. A two-compartment model of this type is portrayed in figure 33.

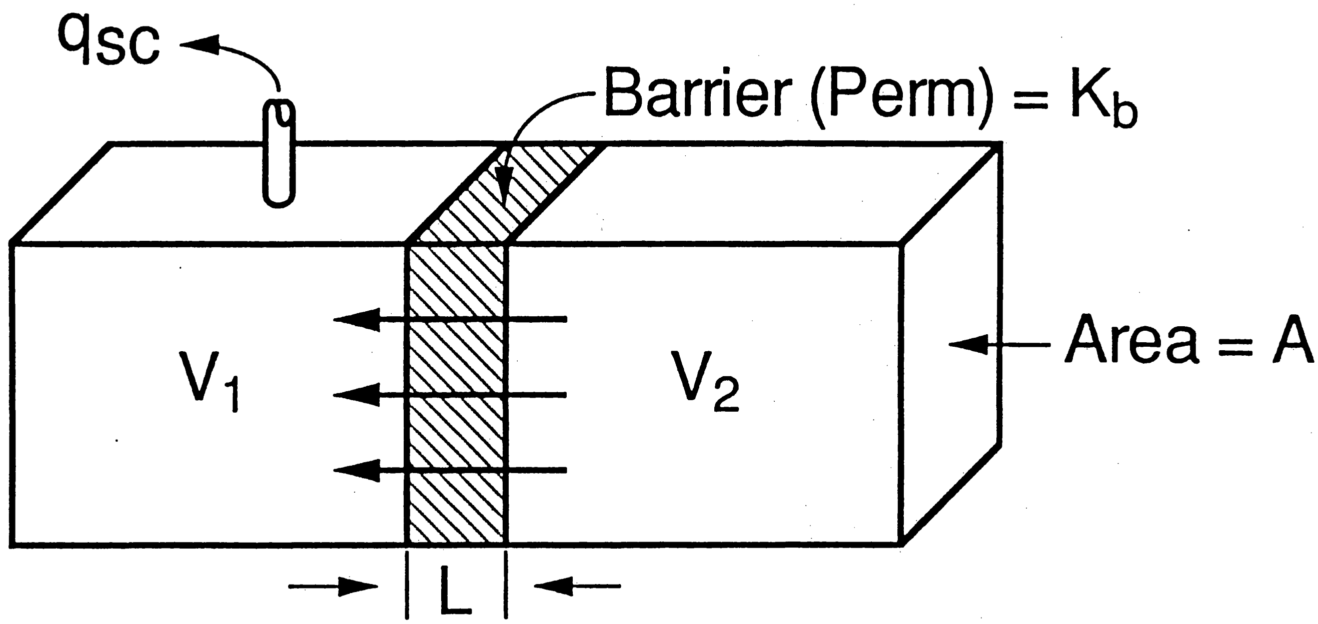

Figure 33. Idealized tank model of a one-dimensional reservoir.

A key element in this idealization of a reservoir is that the pressure within a compartment is spatially uniform at all times; hence, the pressure modeled for a compartment is in fact the spatial average pressure in a real compartment. A first step in this study was thus to determine, by simulation, the conditions under which conventionally measured shut-in pressures in gas wells are in reasonable agreement with spatial average pressures. Only then are shut-in pressures appropriate for P/Z type analysis or for study with models such as described here.

To investigate this question, one-dimensional and two-dimensional finite difference simulators were configured to represent a two-compartment continuous reservoir. Tests were first made in multiple runs to evaluate the required grid refinements for representing the high-permeability contrast between compartment and barrier without significant truncation error. Then, having established this, many runs were made using varying parameters and well locations to determine criteria for equivalence of shut-in well pressure and spatial average pressure of the compartment drained by the well.

Correlations were developed in these studies that allow prediction of the required duration of shut-in for a well to assure that the final shut-in pressure is a good approximation of the spatial average pressure of the compartment drained by the well. These studies also demonstrated that this result was essentially independent of the spatial location of the well relative to compartment boundaries.

Typical results generated for one well draining a single compartment with no communication to other compartments are shown in figure 34. There the simulated shut-in data are plotted as $(P/Z)/(P/Z)_i$, with i denoting initial value; versus G_P/G, where G_P is produced gas (scf) and G is original gas in place (scf). The parameter labeling the curves is the dimensionless shut-in time.

$$\Delta t_D = 0.063 \frac{K\Delta t}{\phi(\mu c)_i \, r_w^2} \tag{1}$$

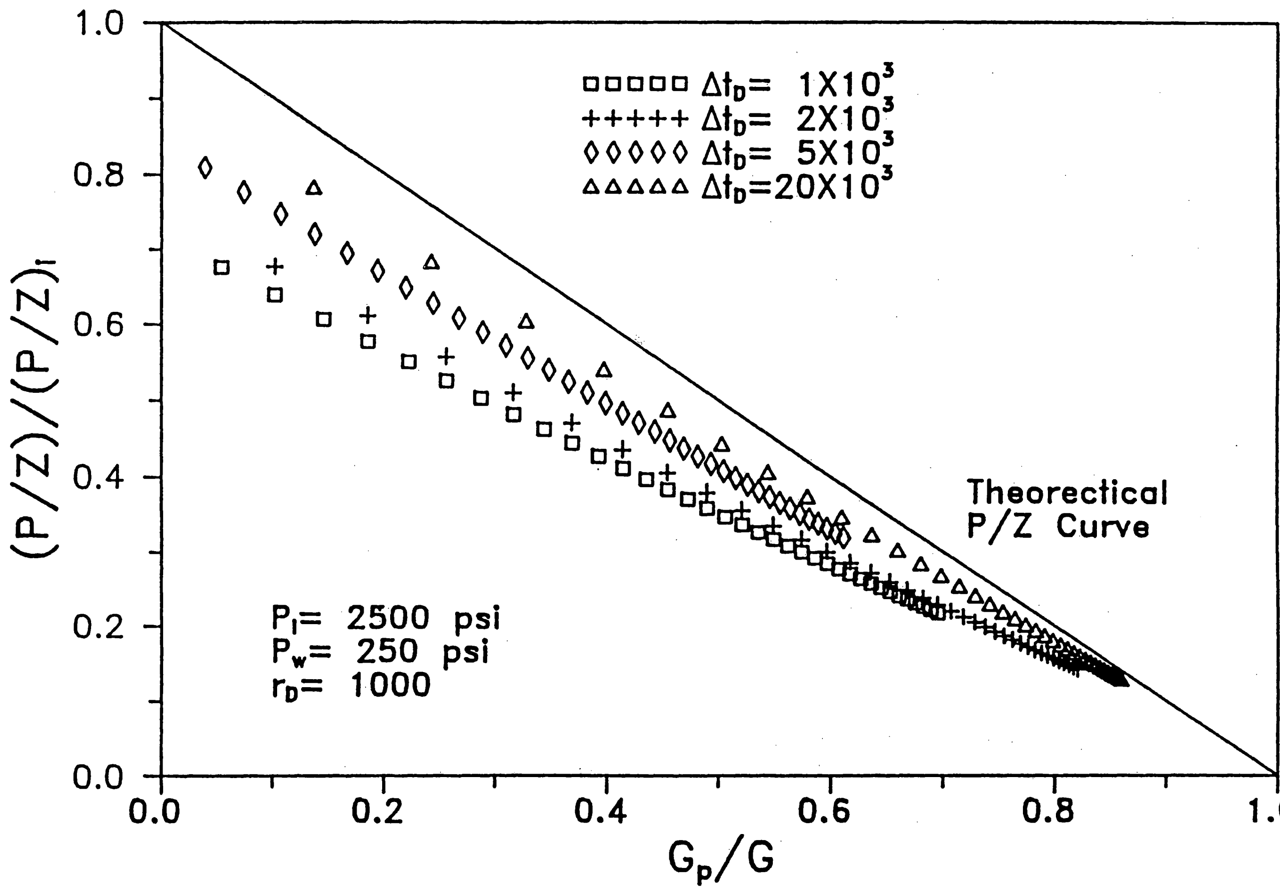

Figure 34. Effect of variations of Δt_D on P/Z behavior.

Here the symbols and units are

Δt=shut-in time (days)

K=permeability (md)

ϕ=porosity, (fraction)

μ=viscosity (cp)

c=compressibility (psi^{-1})

r_w=wellbore radius (ft)

and i denotes evaluation at original pressure.

Significant features of figure 34 are that the slopes of the lines for various Δt_D's differ from the ideal straight line, and all intersect the same terminal point. The criterion evolved for an acceptable shut-in time was that the vertical intercept of this plot at G_p=0 be on the order of 0.95 or greater. Thus, correlations were developed whereby one can predict the required shut-in time for given permeability, production rate, etc., to assure that the final, measured shut-in pressure is a good approximation to the spatial average pressure of the drained compartment. Correlations similar to those in figure 34 were generated for initial reservoir pressures of 2,500 psi, 5,000 psi and 7,500 psi.

An analytical model was developed to represent the gas material balance, or conservation of mass, for the two-compartment reservoir depicted in figure 33. It should be noted that the entire derivation was based on the assumption that there is no water influx. The final derived equation shows that the P/Z behavior for the compartment containing the well will be substantially different from the theoretical straight-line P/Z behavior. This is depicted in figure 35. Here, the early production history begins as that for a well draining a closed compartment with volume V_1. This is indicated by slope 1 being inversely proportional to V_1. For later history, and larger G_p, the graph is that for a well draining a reservoir of volume $V_1 + V_2$, but displaced downward from the theoretical "single compartment" line by a constant amount, δ. Furthermore, at any selected abandonment pressure a quantity, ΔG_p, of unrecovered reserves will remain in the reservoir.

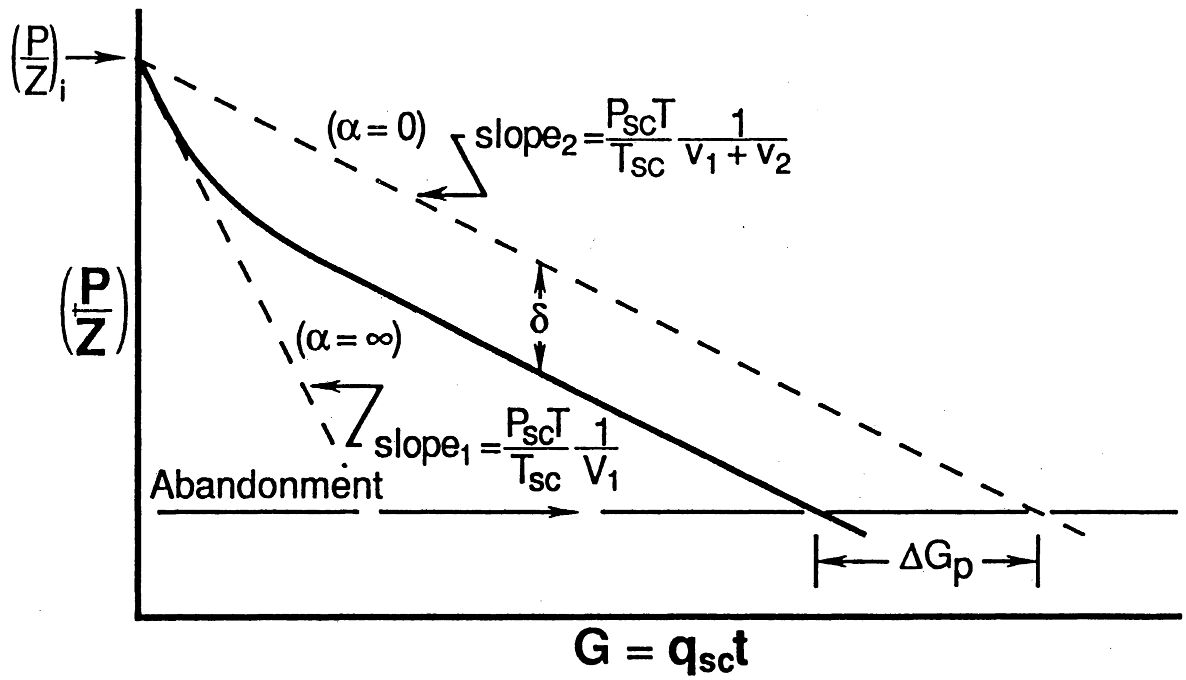

Figure 35. Ideal P/Z behavior in a compartmentalized reservoir.

It was observed that the critical parameters in determining δ and ΔG_p are the dimensionless groups

$$\alpha = \left(\frac{c_b \mu_b L}{K_b A_b}\right) q_{sc} \text{ and } \beta = \frac{V_1}{V_2}, \tag{2}$$

where α is composed of the flow rate at the well and the fluid and physical properties of the barrier evaluated in the barrier, and β is the ratio of the drained volume to the undrained volume. Thus, a set of parametric studies was conducted to determine the significance of α and β. Once the sensitivity of the model and the resulting P/Z behavior to these parameters was determined, the technique could be used as a history matching tool.

Figure 36 shows the results of sensitivity analyses to changing α when compared with actual field data from a well completed in the Vicksburg S,S sandstone in McAllen Ranch field (the well is the same for which data are shown in figure 14). Note that changing α primarily changes the point at which the curves break away from the original slope line, which is a function of V_1. At larger values of G_p, the lines are essentially parallel. Figure 37 illustrates a sensitivity study to changing β compared with the same field data. Here, changing β affects the slope of the line but not the "break away" point. Thus, since the results of changing the two parameters are distinctly different, the model may be used to generate a unique history match to the measured field data.

Figure 38 presents the results of this match. The value of α was determined to be 55 and β appears to be on the order of 1/20. Admittedly there is no way to discern the individual components of α (K_b, A_b, L) at this point. Furthermore, determination of α and β in low-permeability reservoirs is tenuous. If V_1 is approximated from the initial slope of the P/Z line, however, then we can obtain an estimate for V_2. Combining the knowledge of the volume of the undrained compartment, V_2, with detailed geologic and geophysical studies and pressure-transient testing makes targeting potential infill drilling locations possible.

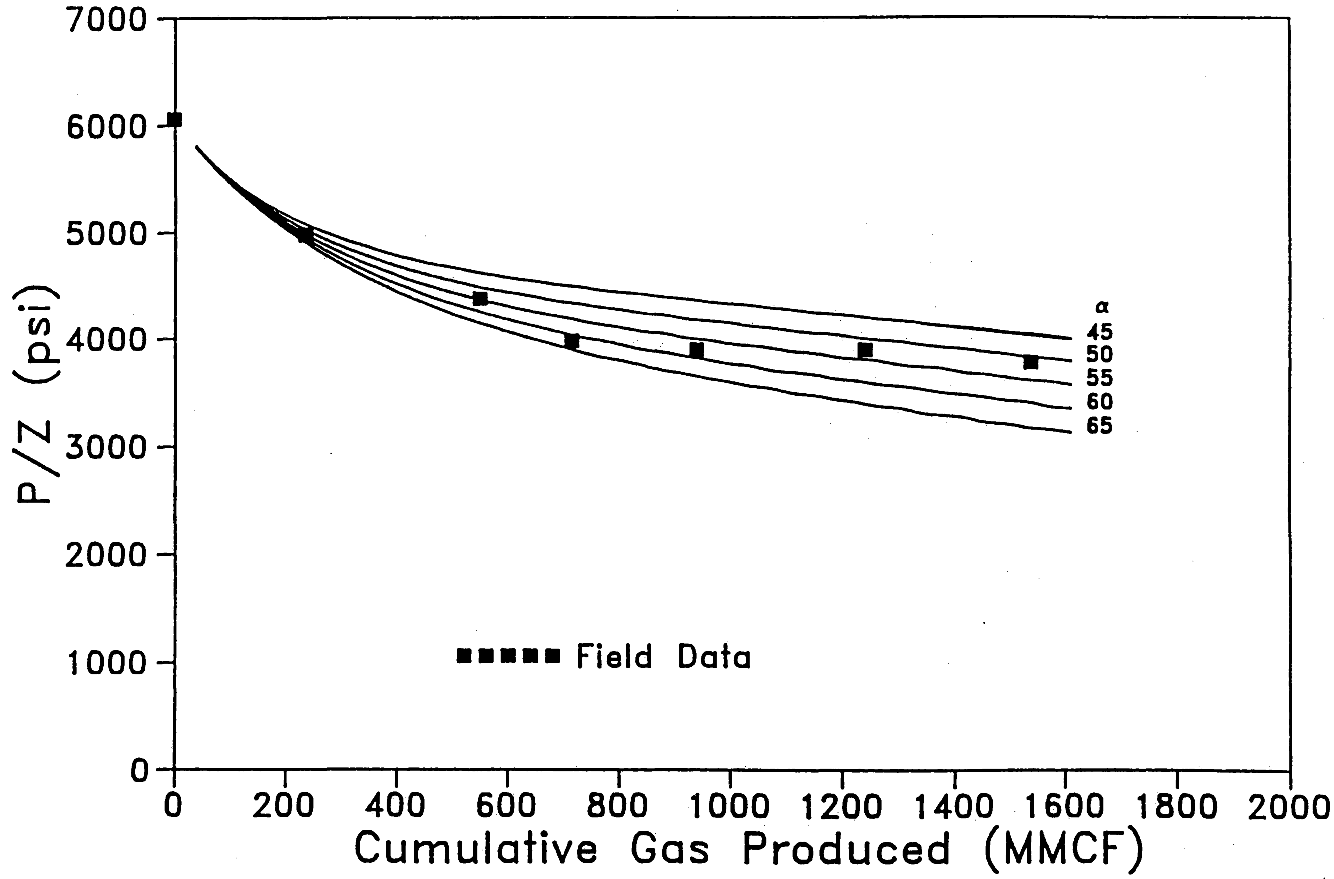

Figure 36. Field application of production history matching. Sensitivity to changing α.

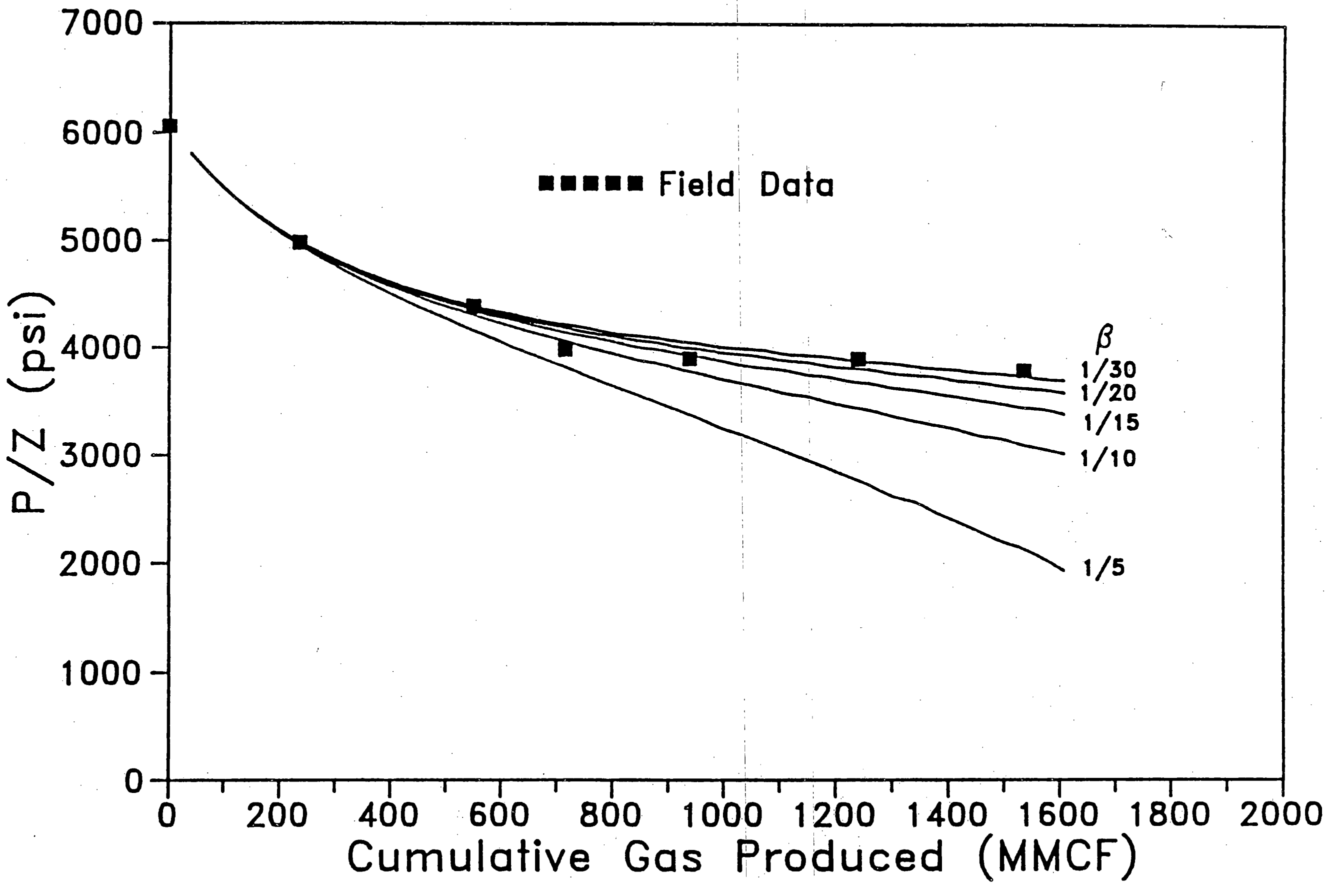

Figure 37. Field application of production history matching. Sensitivity to changing ß.

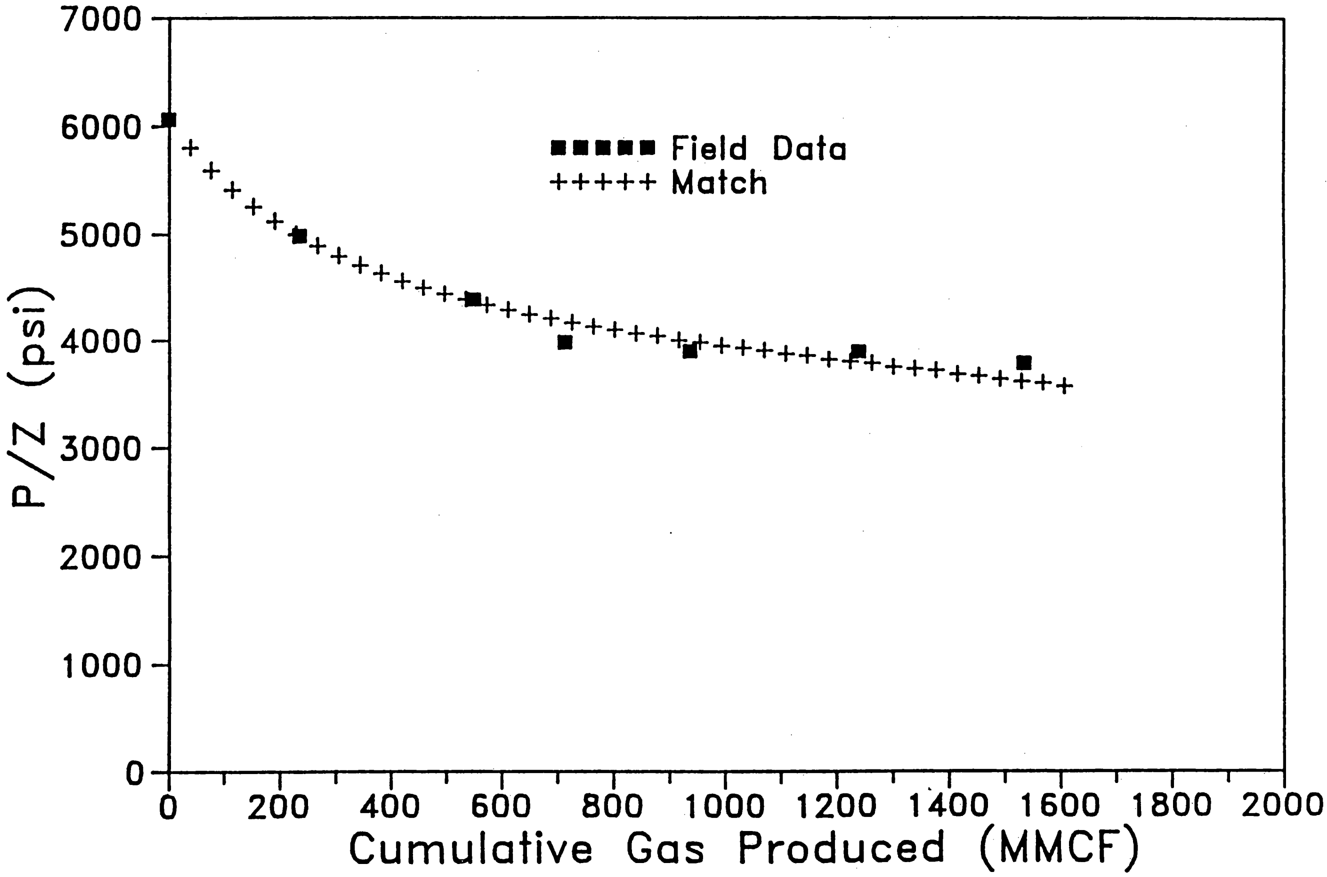

Figure 38. Field application of production history matching.

Implicit in this history matching via selection of constants α and β are the assumptions of a constant production rate, q, and shut-in periods for measuring pressures of sufficient duration as dictated in studies illustrated in figure 34. In tight reservoirs such as that found in McAllen Ranch field, this latter assumption may be only marginally valid. The constant-rate assumption is also not appropriate generally but may be a good approximation in many instances.

To make this model more realistic it is being extended to incorporate a large number of compartments, some having active water drive, and some accommodating multiple wells that may have completions in more than one compartment. Furthermore, the history matching scheme to be utilized will incorporate the detailed rate history of each well; the system will even accommodate simulation of recompletions and well stimulations. This expanded model should prove to be a valuable tool for evaluating production data to diagnose reservoir compartmentalization. The extended model will of course be applicable only to shut-in pressure data, satisfying the criteria discussed in figure 34.

Simulation Studies of Gas Flow in Crossbedded Reservoirs

The sandstone reservoirs being investigated in the SGR project are primarily fluvial and deltaic depositional systems and frequently exhibit crossbedding. The effect of these structures on flow characteristics has not been studied to any significant extent and, in particular, their effect on well-test results has not been established. Specifically, how should well-test interpretation incorporate the existence of crossbedding? Flow and shut-in pressure-buildup tests are to play a significant role in providing reservoir parameters in the SGR studies, so REC has undertaken a study of the effects of crossbedding on well tests.

This study focused on the flow of a single-phase real gas in a homogeneous crossbedded reservoir. In particular, the problem of a single well draining a cylindrical reservoir was examined as shown in figure 39. In this crossbedded system (consisting of uniform sand laminae all of equal thickness and permeability, alternating with uniform layers of silty, shaly

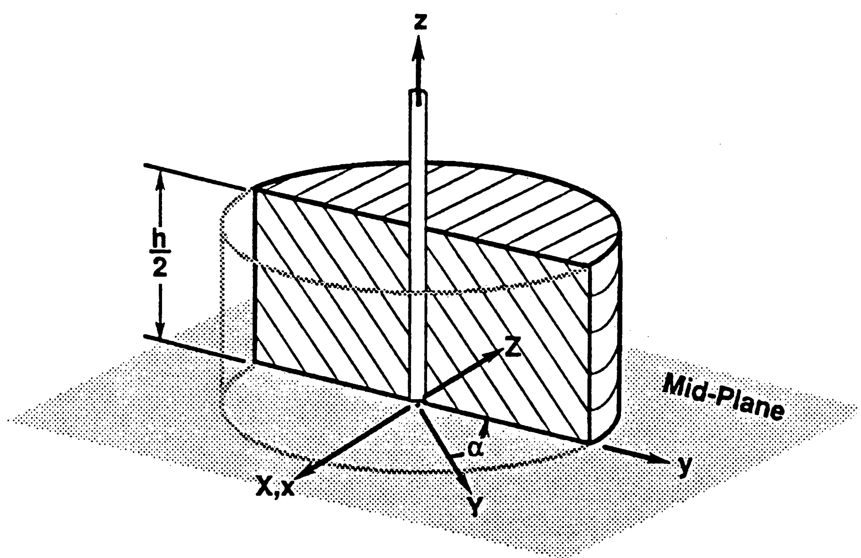

Figure 39. Geometry of a 3-D crossbedded reservoir.

laminae also all of equal thickness and permeability) the large-scale permeability characteristics can be approximated as uniformly anisotropic. That is, the layered system is replaced by a homogeneous system having permeability K_1 parallel to the plane of the laminae and K_2 normal to this plane.

The mathematical equation describing the conservation of mass, together with the necessary initial and boundary conditions, was formulated, and the resulting partial differential equation was solved by the method of finite difference approximation. The formulation and solution techniques were successful in modeling the crossbed flow problem. The simulator was then applied to evaluating the application of conventional gas well testing techniques in a crossbedded reservoir. The study showed that for both flowing and shut-in well tests the classical methods for evaluating reservoir permeability or permeability thickness are applicable to crossbedded reservoirs. The dependence of effective permeability on the crossbed angle was demonstrated (fig. 40), and it was shown that one effect of crossbedding is a negative skin factor. This knowledge will be useful in evaluating wells in these reservoir studies.

Finally, the simulator was used to study the general drainage behavior in a crossbedded reservoir. The simulation describes anomalies in the near-well-bore flow due to crossbedding that results in a nonuniform or spatial dependence of flow of fluids into the well bore. Also, the large scale drainage is affected by crossbedding, and it was shown that some portions of the reservoir are in weak communication with the well and exhibit slow drainage.

SUMMARY

Activities during the first year of the SGR project included screening of gas fields predominantly in South-Central and South Texas, selection of fields as candidates for studies of reservoir heterogeneity, and design and implementation of data-acquisition programs in cooperative wells. A comprehensive workplan that includes integrated geological, petrophysical, geophysical, and engineering studies was prepared. A methodology for

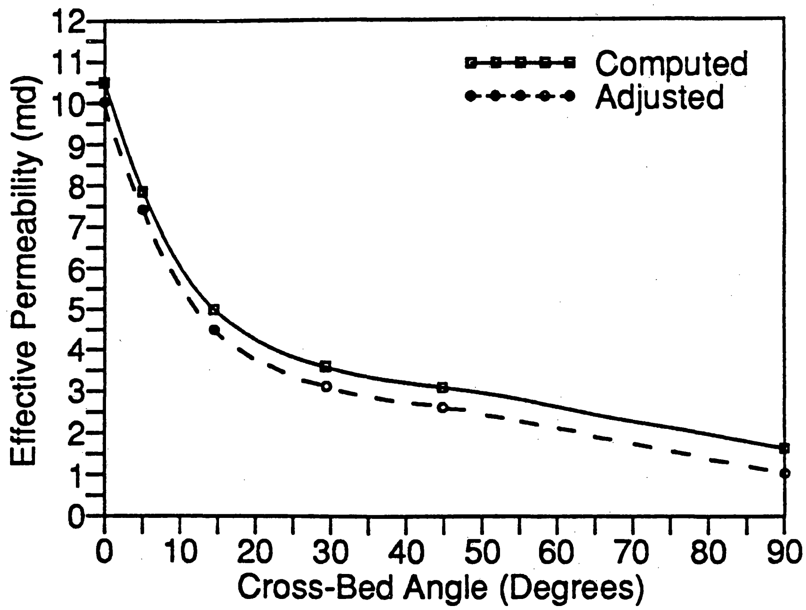

Figure 40. Effective permeability versus crossbed angle.

geological and engineering screening of sandstone reservoirs was developed and applied to leading candidate fields. As part of the screening process, field operators were contacted to solicit their participation in the project. Active involvement of Mobil Exploration and Producing U.S., Inc., Oryx Energy Company, and Shell Western Exploration and Production, Inc., was secured.

A computerized data-base system using Zycor's RCS-II software was acquired. RCS-II interacts with Radian Corporation's CPS-PC mapping software. Identical versions of the system that were installed at the Bureau of Economic Geology and at Research and Engineering Consultants and an input device for well log traces installed at ResTech ensure integrated studies.

Seeligson, McAllen Ranch, Lake Creek, and Stratton-Agua Dulce fields were selected for detailed studies because these fields are representative of a spectrum of depositional systems and reservoir heterogeneity in highly productive gas reservoirs in the Texas coastal plain. Producing intervals are fluvial Frio reservoirs in Seeligson and Stratton-Agua Dulce fields, deltaic Vicksburg reservoirs in McAllen Ranch field, and deltaic Wilcox reservoirs in Lake Creek field. Initial results of the studies indicate that the fields selected have a high potential for untapped gas reserves due to reservoir compartmentalization, and that maximum reservoir heterogeneity occurs in fluvial Frio reservoirs in Stratton-Agua Dulce fields.

New data were acquired in two cooperative wells drilled as deeper-pool tests in Seeligson field and in one offset well in McAllen Ranch field. The data include cores, open- and cased-hole logs, vertical seismic profiles (VSP's), and sequential formation-pressure tests. Furthermore, programs were prepared for additional data collection in the Seeligson and Lake Creek fields. The program at Seeligson field is centered in the area of the two cooperative wells and includes VSP's, cross-borehole seismic tomography between closely spaced wells, and pressure-interference tests using producing and temporarily abandoned wells. A zero-offset VSP is programmed in a well to be deepened in Lake Creek field. The additional VSP velocity control will be used in reprocessing and reinterpreting portions of the 2-D seismic data needed for the project.

Results thus far suggest that heterogeneity can be defined through geologic means (facies mapping, cross sections, isopach maps) and geophysically as well, as evidenced by terminations of reflectors on VSP's. Moreover, some key questions have been formulated as to the relations between components of major sandstone packages, such as the S sandstone at McAllen Ranch field and the geometry of hydraulic fractures as created to help produce Vicksburg reservoirs at that field.

Whereas geological and geophysical depictions suggest heterogeneity, pressure continuity will be focused on more fully to help define the flow units made up of the sandstone components defined as the physical reservoir framework. The upcoming data collection at Seeligson field involving pressure-interference testing will move the project in that direction, as will acquisition by the operator of pressure data in Lake Creek field.

ACKNOWLEDGMENTS

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Appendix A.

Geological and Production Summaries of Selected Gas Fields of the Texas Coastal Plain

INTRODUCTION

Appendix A summarizes the results of investigations undertaken and forms part of Subtask 1.3a, Geological Selection Criteria, under Workplan, Version 3.0, of the Bureau of Economic Geology's (BEG) Secondary Gas Recovery: Targeted Technology Applications for Infield Reserve Growth (SGR) project. The appendix contains an introductory geologic review followed by summaries of geologic and production data for 14 gas fields selected after initial screening of fields in the South-Central and South Texas coastal plain. The fields are located in Railroad Commission of Texas (RRC) districts 3 and 4 (fig. 2, table A-1). Three fields are located north of the San Marcos arch in the Houston embayment: Lake Creek, Lissie, and Sheridan. Eleven fields are located south of the arch in the Rio Grande embayment: Portilla, Rooke, White Point East, Stratton-Agua Dulce, Seeligson, McAllen Ranch, Lyda, Flores, Jeffress, Monte Christo, and Yturria.

Drilling and completion activities in gas fields in the area were monitored using biweekly reports prepared by Envirocorp and weekly reports obtained from Petroleum Information (PI). Data were then compiled from fields in which recent operator activity was relatively high. To provide a wider spectrum of depositional and structural settings, data were also compiled for fields in which operator activity has been low or absent but that may be suitable for research activities. The data incorporated in the field summaries were obtained from (1) trade and technical literature, (2) BEG's "Atlas of Major Texas Gas Reservoirs" (Kosters and others, 1989), (3) Dwight's production summaries, (4) hearing files at the RRC, and (5) wire-line logs from BEG and RRC files.

The following characteristics were identified for each field summarized: (1) the regional stratigraphic and structural framework, (2) the gas-producing intervals, (3) the gas play containing the gas reservoirs, (4) the depositional systems of the productive intervals, and (5) the potential for reservoir heterogeneity and related possibilities for unrecovered reserves.

Table A-1. Geologic and production summaries of selected gas fields of South and Central Texas.

Field name	County (RRC District)	No. of compl. interv.	Cum. prod. (Bcf)	Prod. horiz.	Prod. depth (ft)	Structure	Potential for reservoir heterogeneity	Operator activity	Data base
Lake Creek	Montgomery (3)	24	218	Wilcox	8,700 to 13,000	Simple	Good	Low	Very good
Lissie	Wharton (3)	33	96	Miocene; Wilcox	2,450 to 9,600	simple; complex	Good Good	None	Fair
Sheridan	Colorado (3)	156	100	Frio; Yegua; Wilcox	3,300 to 13,800	Simple; complexly faulted	Good; mod. to good; good	None	Fair
Rooke	San Patricio (4)	5	60.5	Frio	7,000	Simple	Good	Moderate	Fair
Portilla	San Patricio (4)	65	52	Miocene; Frio	3,100 to 8,500	Simple; simple	Good; low	Low	Good
White Point E.	San Patricio (4)	377	388	Miocene; Frio	1,300 to 11,800	Simple; complex	Good; low	Low	Fair
Stratton-Agua Dulce	Jim Wells (4)	300	2,600 (Str)	Frio	1,500 to 9,000	Faulted	Good	Very high	Fair to good
McAllen Ranch	Hidalgo (4)	80	770	Frio; Vicksburg	7,000 to 15,000	Complexly faulted	Good	High	Excellent
Lyda	Starr (4)	23	19	Vicksburg	7,000 to 9,500	Complex	Good	Moderate	Fair
Flores-Jeffress	Starr and Hidalgo (4)	100	259	Frio; Vicksburg	4,400 to 12,400	Simple; complex	Mod. to good; mod. to good	Low	Fair
Monte Christo	Hidalgo (4)	61	237	Frio; Vicksburg	5,300 to 15,000	Complexly faulted	Moderate to good	Low	Good
Yturria	Starr (4)	80	26	Frio; Vicksburg	4,000 to 5,150	Simple; faulted	Mod. to good; mod. to good	Low Low	Fair Fair

The results of the compilation are summarized in table A-1 and figure 2, as are relevant attributes for each field (table A-1). Figure A-1 illustrates the depositional episodes and stratigraphic nomenclature of the Tertiary System in the Texas Gulf Coast Basin and places in stratigraphic context the gas reservoirs of each field.

Geologic Setting

Tertiary deposits of the Texas Gulf Coast Basin mainly accumulated in two depocenters, the Rio Grande embayment in South Texas and the Houston embayment in Southeast Texas. The San Marcos arch of Central Texas separates the embayments (fig. 2), each of which contains a thick wedge of Tertiary clastic sediments that thin over the San Marcos arch.

The continental shelf prograded episodically during the Cenozoic to form the Gulf coastal plain. Each major episode of shelf margin progradation resulted in the formation of a laterally persistent, growth-fault zone when fluvial and deltaic systems prograded across the shelf and were deposited on underconsolidated, slope and basinal mud-rich facies. The Wilcox, Vicksburg, and Frio fault systems were thus formed along the South Texas coastal plain (fig. 2). Movement on the faults was syndepositional and related to shelf-margin progradation.

Stratigraphy

Onshore sandstone gas reservoirs along the Texas Gulf Coast commonly lie in the proximal portions of progradational sequences in which sandstones intertongue with shales basinward. Progradation was not simultaneous along the entire Gulf Coast Basin. Formations, defined lithologically, are thus time transgressive. The fields that were summarized contain reservoirs deposited during the Wilcox, Vicksburg, Frio, and Miocene depositional episodes (fig. A-1).

The Wilcox Group is the oldest progradational package in the fields summarized (figs. 2, A-2). Wilcox reservoirs produce natural gas in Lake Creek, Lissie, and Sheridan fields. The

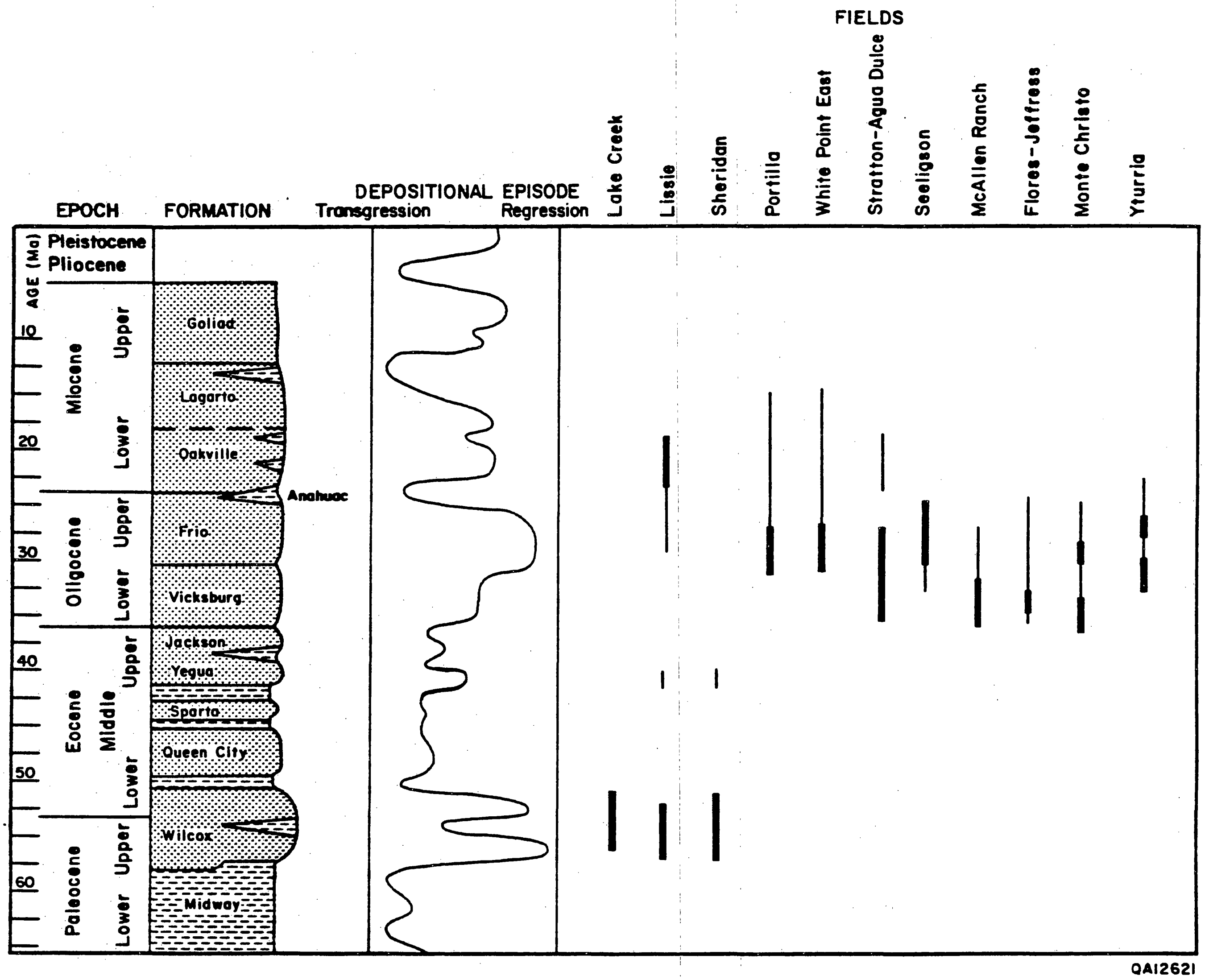

Figure A-1. Stratigraphic chart of Cenozoic sediments of South-Central and South Texas Gulf Coast. Vertical bars indicate producing intervals in the gas fields summarized. Bar thickness indicates relative importance of gas production.

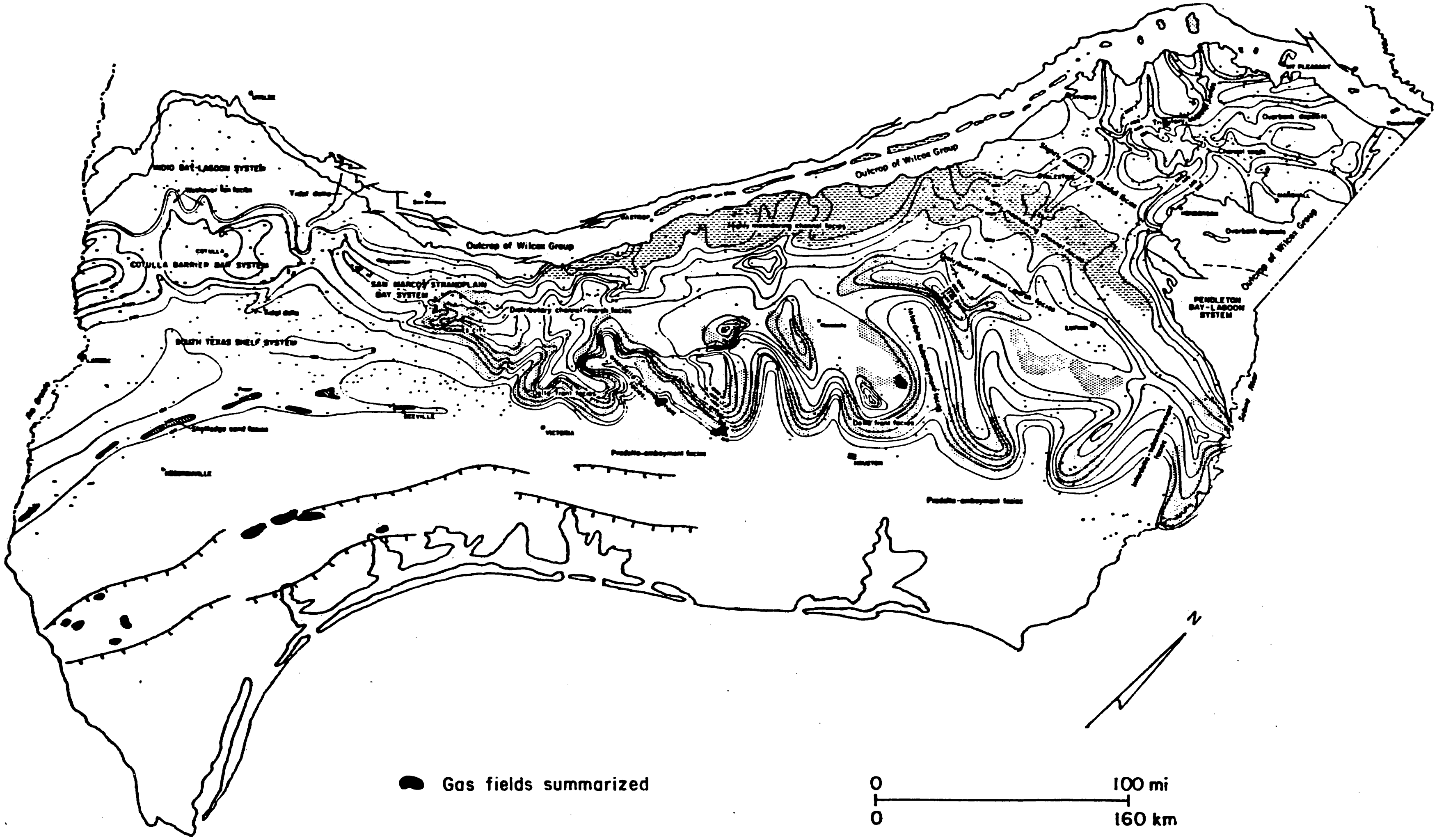

Figure A-2. Wilcox depositional systems (Eocene), Texas Gulf Coast. Gas reservoirs in the Lissie, Sheridan, and Lake Creek fields form part of the Rockdale delta system, which grades southward into the San Marcos strandplain-bay system. From Fisher and McGowen, 1969.

sandstone reservoirs were largely deposited in lobate, river-dominated deltas of the Rockdale delta system (Eocene). Lissie and Sheridan fields are located near the south end of the delta system, which intertongues southward with the San Marcos strandplain system (fig. A-2).

The Oligocene Vicksburg Formation contains important natural gas reservoirs in several fields studied (fig. 2). The Vicksburg is underlain by shales of the Jackson Group and is overlain by sandstones and shales of the Frio Formation. The Vicksburg-Jackson boundary is usually drawn at the lithologic contact between sandstones of the lower Vicksburg and underlying shales of the Jackson Group. The Vicksburg (the upper part of which comprises mostly shales) and the overlying Frio (which contains thick sandstones in its lower part) are generally differentiated on the basis of lithology. In addition to lithology, the occurrence of benthonic foraminifera is commonly used in South Texas to identify and differentiate deposits of the Jackson, Vicksburg, and Frio. For example, the index foraminifer *Uvigerina mexicana* is considered characteristic of the basal Vicksburg Formation. Also, the Vicksburg Formation has been distinguished from the overlying Frio Formation by the occurrence of the Vicksburg index foraminifer *Textularia warreni*. However, because in South Texas the lowermost sandstones of the Frio may contain *Textularia warreni*, some workers define the upper Vicksburg strata by the occurrence of *Loxostoma* (B) *delicata*.

The Vicksburg Formation was strongly affected by movement along faults of the Vicksburg fault zone (fig. 2), which is characterized by regional continuity along strike and pronounced dip reversal. Vicksburg deposition in South Texas was the result of varying intensities of progradation, subsidence, and marine reworking. The Vicksburg Formation in the fields studied has commonly been interpreted as deltaic (fig. A-3) (Han, 1981; Han and Scott, 1981; Galloway and others, 1982). However, Berg and others (1979) proposed that the Vicksburg Formation in this area contains deep-sea fan deposits. The lower Vicksburg is interpreted as the deposits of lobate deltas in which thick sequences of dip-elongate sandstones developed (Han, 1981). The middle and upper Vicksburg are regarded as the deposits of wave-dominated, cuspate deltas in which more strike-aligned sandstones were deposited.

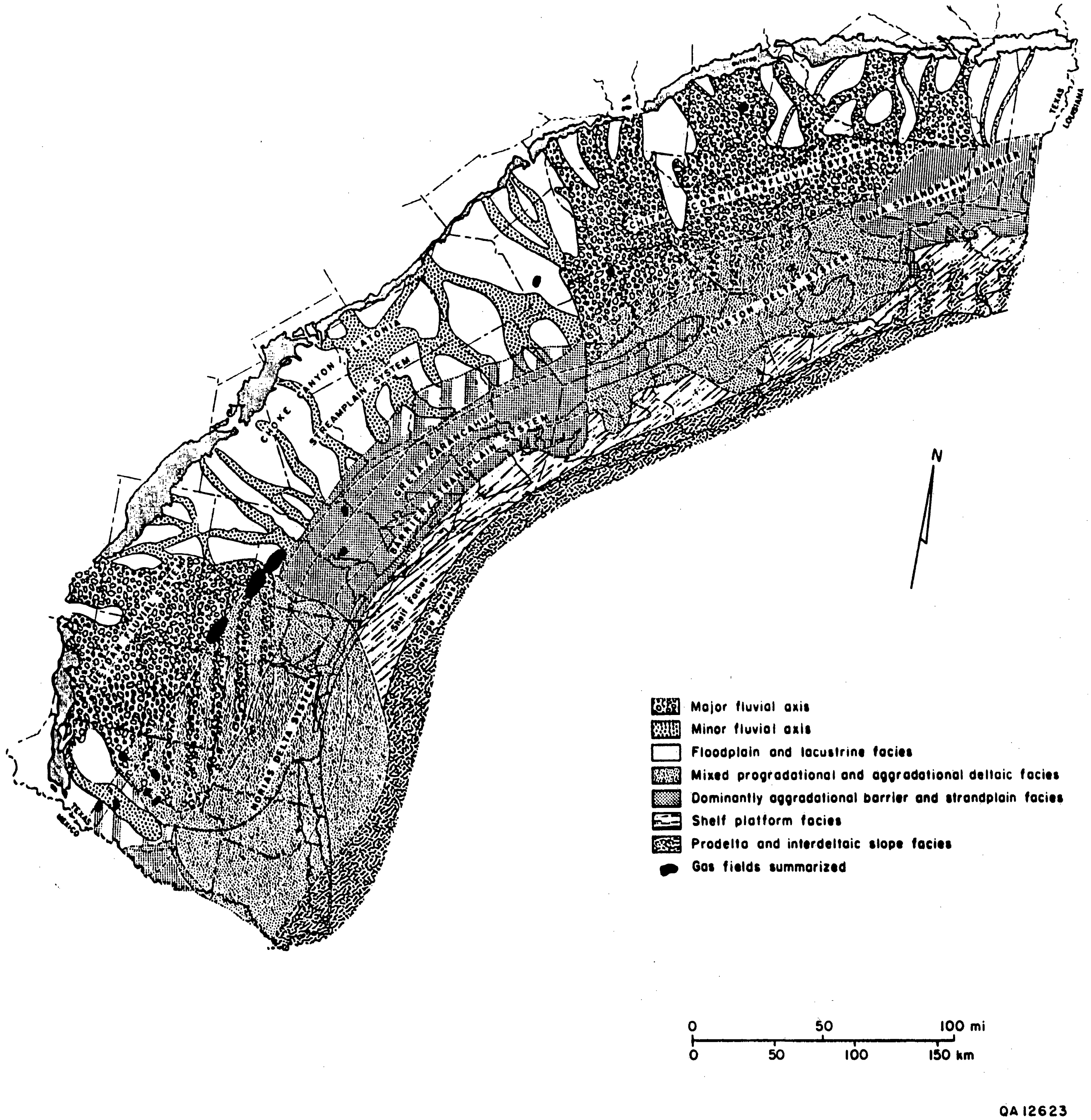

Figure A-3. Vicksburg and Frio depositional systems, Texas Gulf Coast. From Galloway and others, 1982.

Deposition of the upper Oligocene Frio Formation followed a short transgressive event (fig. A-1). The shelf margin prograded and the Frio growth-fault zone developed in response to progradation out to the the preexisting unstable shelf margin during early Frio deposition (fig. 2). The Frio fault system controlled deposition, with the Frio thickening as much as ten times basinward across growth faults.

Prominent deltas developed during Frio and Vicksburg times (fig. A-3) in the Rio Grande embayment (the Norias delta system) and in the Houston embayment (the Houston delta system) (Galloway and others, 1982). The deltas were separated by the Greta/Carancahua barrier-bar/strandplain system, in which relatively thick, progradational, laterally continuous reservoir sandstones were deposited. In South Texas, Frio sediments were deposited in large, bedload-dominated rivers of the Gueydan fluvial system. In a gross sense, Frio fluvial sandstones form laterally extensive sheets. However, the dip orientation of the channel sandstones and internal permeability barriers (floodplain, thin levee deposits) commonly result in isolated reservoirs that have become targets for incremental gas recovery.

The Miocene Oakville Formation (updip) and the Oligocene-Miocene Anahuac Shale (basinward) overlie the Frio Formation. Following the Anahuac transgression, lower Miocene deposits prograded to near the present-day coastline. The Vicksburg and Frio fault systems were largely inactive, and Miocene sediments are not very deformed in the fields studied. The same pattern of deposition continued with fluvial systems in the Houston and Rio Grande embayments (fig. A-4) (Galloway and others, 1986). Following progradation of the North Padre delta system, the Santa Cruz fluvial system covered much of South Texas. To the north, on the San Marcos arch, the Moulton/Pointblank streamplain system fed into the Matagorda barrier/strandplain system.

In the Middle and Late Miocene, the Mustang barrier-bar and the Realitos fluvial systems followed the established Early Miocene pattern of deposition (fig. A-5). Bed- and mixed-load channel-fill sandstones of the Realitos system form laterally discontinuous reservoirs.

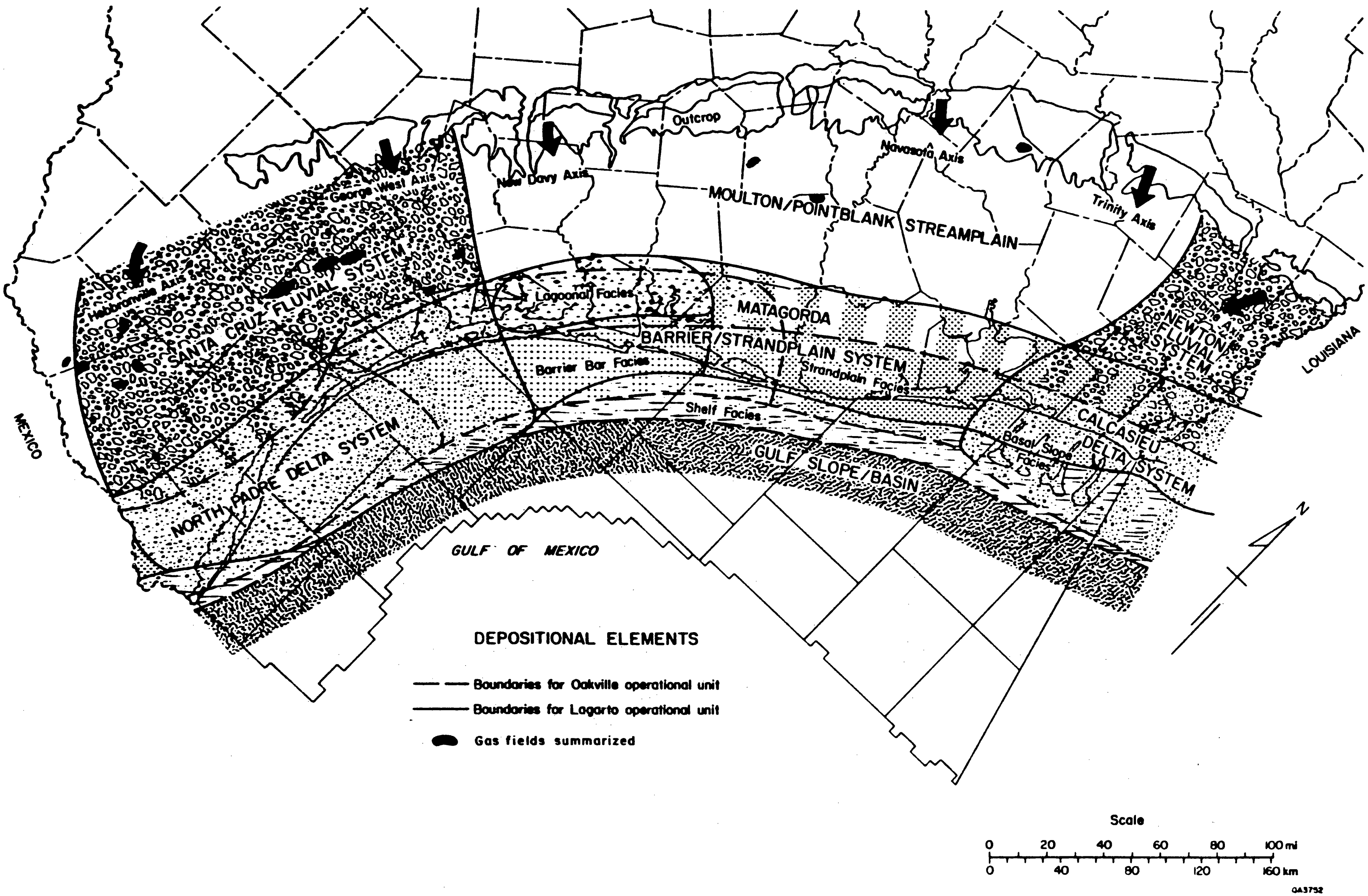

Figure A-4. Lower Miocene (Oakville and Lagarto) depositional systems, Texas Gulf Coast. From Galloway and others, 1986.

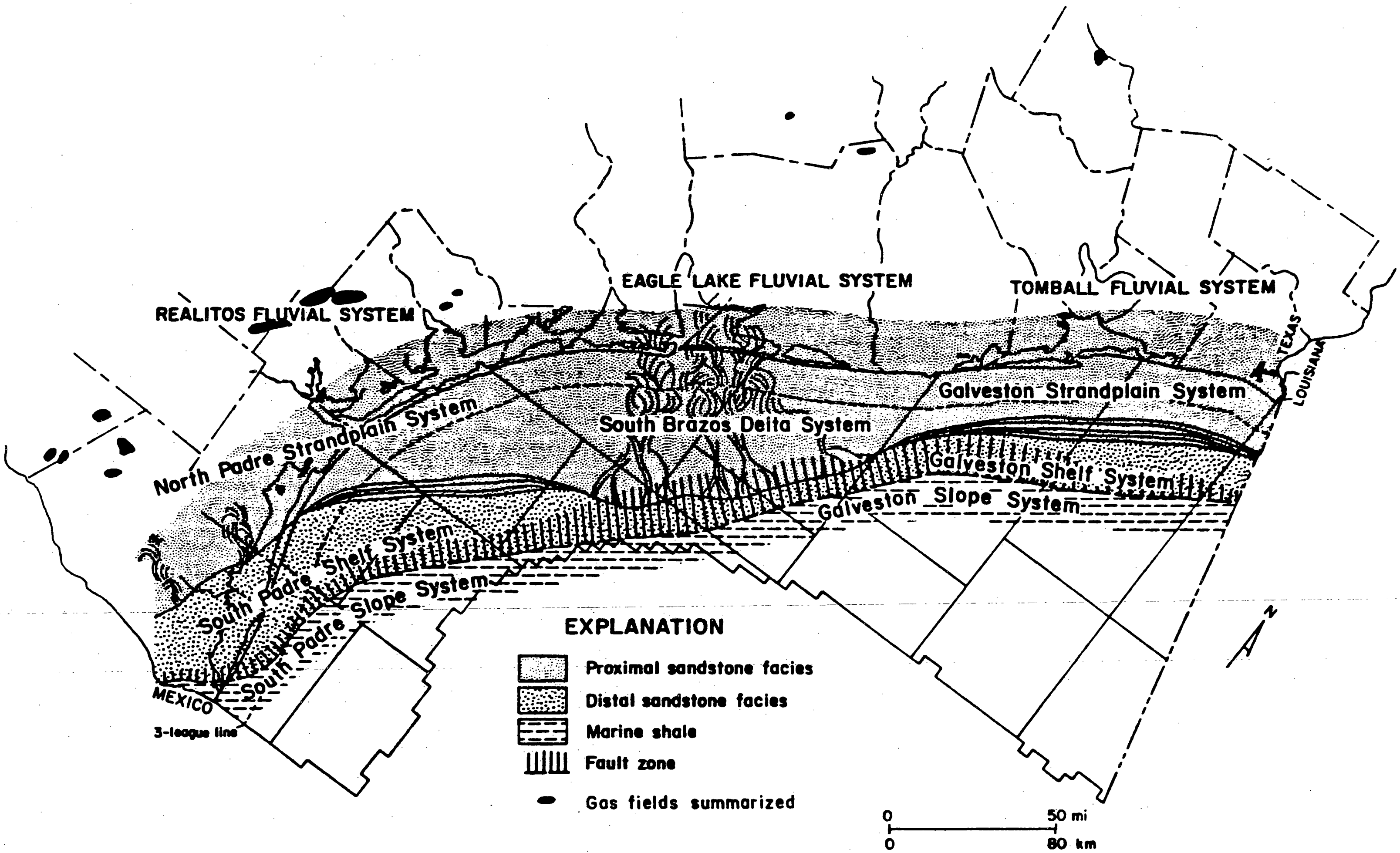

Figure A-5. Middle and Upper Miocene depositional systems, Texas Gulf Coast. From Morton and others, 1988.

Gas Plays

The fields summarized are included in several plays described in BEG's "Atlas of Major Texas Gas Reservoirs" (Kosters and others, 1989) (fig. 3). Gas plays are defined by the depositional system in which the reservoirs lie, although some of the plays are related to both depositional systems and major structural features such as fault systems. The fields studied contain reservoirs belonging to the Eocene Wilcox (WX-1), Eocene Yegua (EO-3), Oligocene Vicksburg (VK-1), Oligocene Frio (FR-4, FR-6, and FR-7), and Miocene (MC-3 and MC-6) plays (table 2).

Wilcox play WX-1 is defined by gas production from Eocene Wilcox deltaic reservoirs along the Wilcox fault zone. Lake Creek, Sheridan, and Lissie fields are included in this play. Eocene play EO-3 is defined by production from Eocene Yegua fluvial and deltaic reservoirs that were affected by movement along the Wilcox, Vicksburg, and Frio fault systems. Lissie field is in the EO-3 play.

The Vicksburg VK-1 play is defined by production from Oligocene Vicksburg deltaic reservoirs along the Vicksburg fault system. McAllen Ranch and Monte Christo are examples of fields producing from the VK-1 play.

Frio play FR-4 is defined by production from Oligocene Frio sandstones along the Vicksburg fault system. Flores, Monte Christo, Stratton-Agua Dulce, Seeligson, and Yturria fields contain reservoirs in this play. Sandstones of the Norias delta and Gueydan fluvial systems (fig. A-3) are significant reservoirs in these fields.

Frio play FR-6 is defined as Oligocene Frio barrier-bar/strandplain sandstones that are located downdip of the Frio fault zone along the middle Texas Gulf Coast. White Point East field produces from reservoirs in this play.

The Frio FR-7 play is identified by production from Oligocene, Frio Greta-Carancahua barrier-bar/strandplain sandstone reservoirs. The sandstones form laterally persistent reservoirs, but studies have revealed localized reservoir inhomogeneities within parts of these systems. Inlet and distributary-channel fills locally may form restricted reservoirs encased within the barrier or strandplain facies. FR-7 reservoirs include those in Portilla field.

The Miocene MC-1 play is identified by production from sandstones deposited on the updip margin of the North Padre delta system. Portilla and White Point East fields are located near the north end of this trend near the transition with the Matagorda barrier-bar/strandplain system (fig. A-4).

Production in the Miocene MC-3 play is obtained from the Miocene Moulton/Pointblank streamplain depositional system. Lissie field produces from this play.

GEOLOGICAL AND PRODUCTION FIELD SUMMARIES

Fourteen gas fields were evaluated and their characteristics summarized (table 2). These fields illustrate typical hydrocarbon distribution, trapping, and recovery in Tertiary reservoirs of the middle and lower Texas coastal plain. The summaries include drilling and completion activities up to January 1989. Production data are mainly from Dwight's reports mostly current to January 1987. The main publications used in the compilation are listed in the references section. The data collected for each field studied are on open file at the Bureau of Economic Geology, The University of Texas at Austin.

Lake Creek Field, Montgomery County

Lake Creek is an oil and gas field located in north Montgomery County, approximately 50 mi northwest of Houston, in RRC district 3 (fig. 2). The field was discovered in 1941 by the Superior Oil Company when drilling the No. 1-1 McWhorter well, which was completed in the Wilcox A sandstone. Field development mostly occurred in the early 1950's. The field encompasses approximately 10 mi^2. The Lake Creek unit (LCU) contains 46 wells and is operated by Mobil Exploration and Producing U.S., Inc. (MEPUS). The field is contiguous with Lake Creek North and Grand Lake fields to the northeast, and with Pine Hurst field to the southwest. Together, these fields extend for approximately 13 miles parallel to depositional strike.

Geologic Setting

The field is located in the Houston embayment and occupies a northeast elongate, gentle rollover anticline on the downthrown block of a growth fault that has more than 500 ft of displacement at the top of the Wilcox (figs. A-6, A-7). Production is from Wilcox sandstone reservoirs (fig. A-8). Wire-line logs suggest that the reservoirs were deposited in stacked deltas ranging in thickness from 200 to 500 ft. The A and B sandstones seem to be laterally extensive. The lower sandstones are discontinuous and have a good potential for reservoir compartmentalization, although low permeability adversely affects gas recovery.

Hydrocarbon Production

The field has produced approximately 218 Bcf of gas. Early production was largely oil, and gas was then recycled to improve recovery. Therefore, the cumulative gas production is probably overestimated. The upper Wilcox reservoirs are all good producers. The B sandstone is the most prolific reservoir. As of January 1987 it had a cumulative gas production of 81.1 Bcf. The J and L sands are the most recently discovered reservoirs. Table A-2 contains production data for the field.

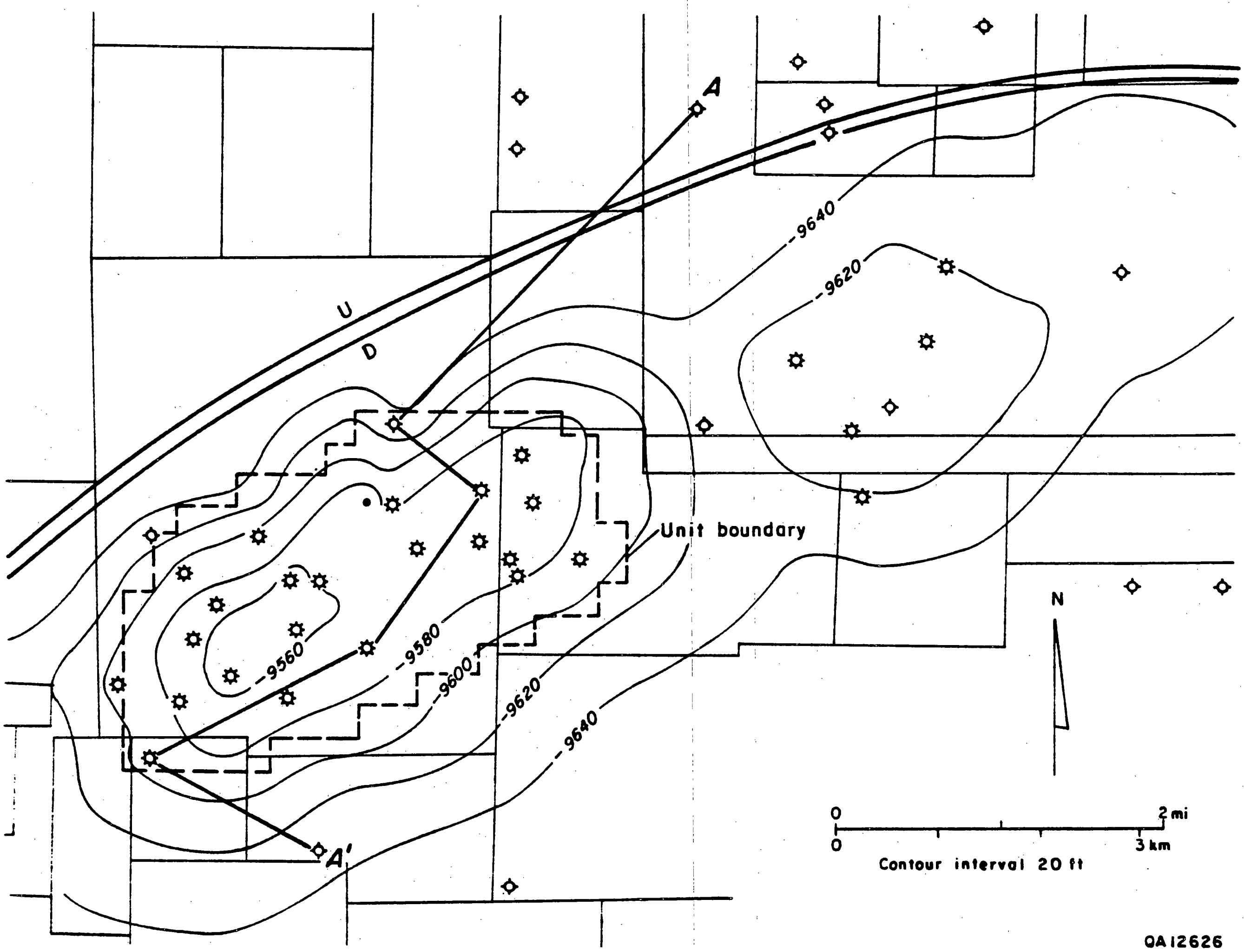

Figure A-6. Structure on top of sandstone B, Wilcox Group, Lake Creek field, Montgomery County. Cross section A-A' shown in figure A-7. From Clarke, 1962.

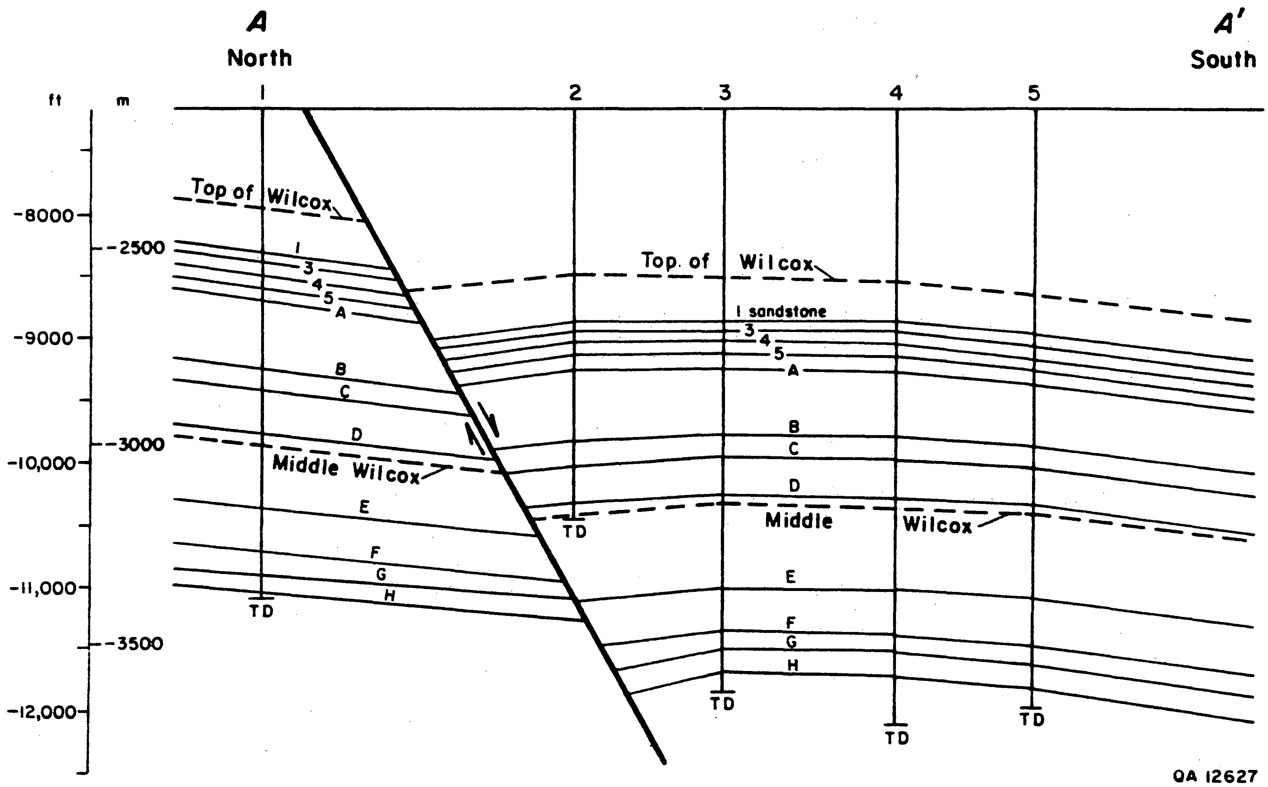

Figure A-7. Structural cross section, Lake Creek field, Montgomery County. Cross-section location shown in figure A-6. From Clarke, 1962.

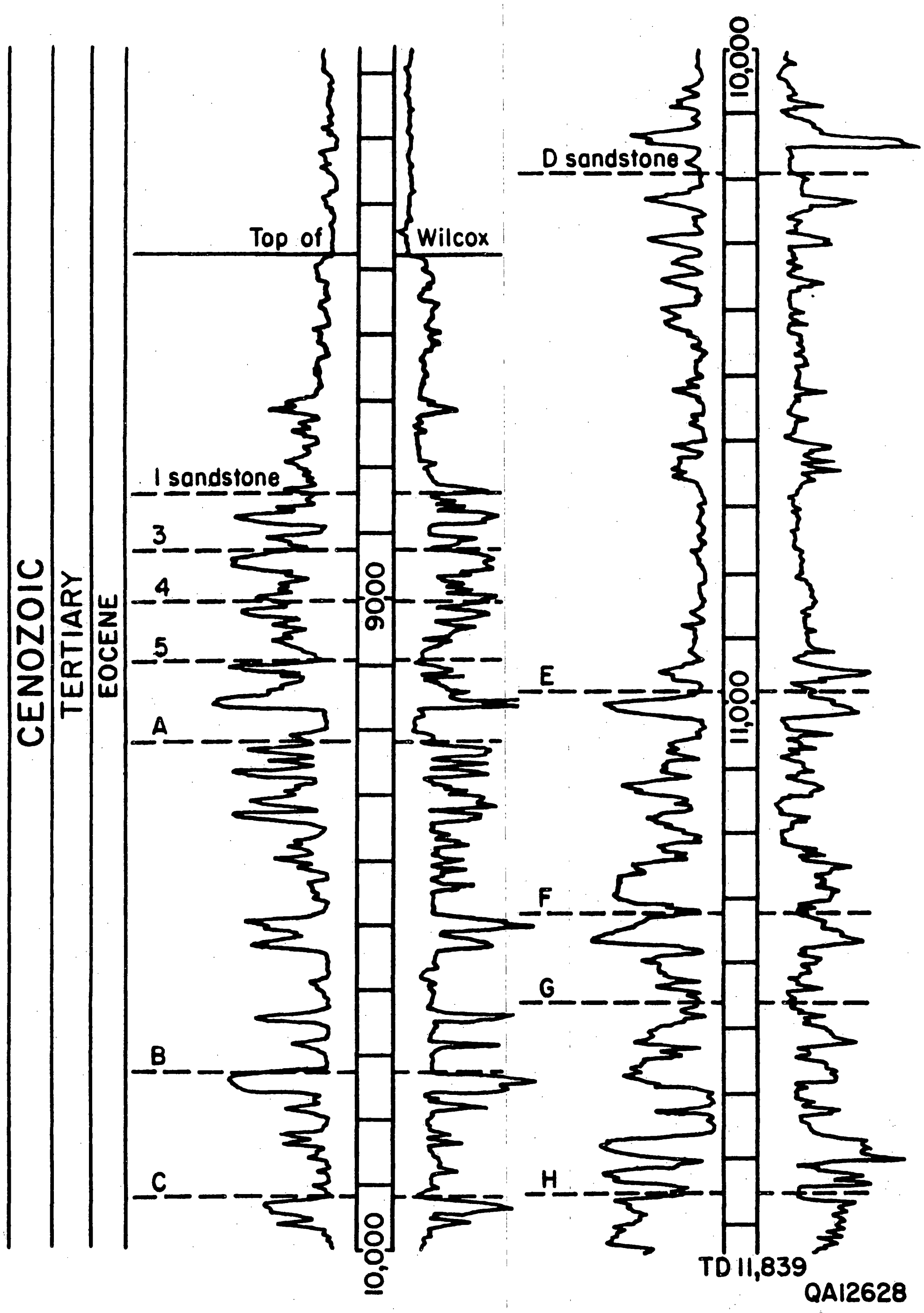

Figure A-8. Well log showing oil and gas reservoirs in the Wilcox Group, Lake Creek field, Montgomery County. From Clarke, 1962.

Table A-2. Production data, Lake Creek field, Montgomery County.

Reservoir name	Depth (ft)	Cum. prod. (MMcf)	Initial BHP/z	Year first produced	Status
Lake Creek A	9,235	20,779	na	1954	SI 1957
Lake Creek B	9,770	81,125	3,275	1950	
Lake Creek C	9,960	14,374	3,490	1952	
Lake Creek D	10,284	16,579	na	1954	
Lake Creek D-9	10,902	19,830	4,994	1982	
Lake Creek E	10,993	21,239	na	1954	
Lake Creek F	11,795	2,567	na	1954	
Lake Creek G	11,604	30,873	4,364	1961	
Lake Creek H	11,790	3,793	4,606	1984	
Lake Creek J	13,030	66	na	1986	
Lake Creek L	12,754	25	na	1985	
Lake Creek La Gloria	8,765	6,478	4,131	1963	

na: not available; SI: shut-in

Recent Activity

Six wells have been drilled in the field in the last 2 yr. Four of these wells were drilled by MEPUS with targets in the F, G, H, and J reservoirs. MEPUS recently completed the Lake Creek unit No. 46 well in the G reservoir.

Lissie Field, Wharton County

Lissie field is located in northwest Wharton County near the Colorado County line. It lies below the hamlet of Lissie, in RRC District 3 (fig. 2). The field, which was discovered in 1950, covers about 8.5 mi^2.

Geologic Setting

Lissie field is situated on the northeast flank of the San Marcos arch, in the Houston embayment, approximately midway between the Wilcox and Vicksburg growth-fault zones (fig. 2). The field is included within the WX-1, EO-3, and MC-3 plays.

Structural Framework

The field is a complexly faulted anticline that trends east-northeast. Structural closure is about 200 ft at the top of the Wilcox (fig. A-9). Numerous normal faults cut through the Wilcox Group in the Lissie area. The most continuous faults strike northeast and show down-to-the-basin separation with typically 200 ft of throw in the Wilcox Group. A second, less continuous fault system trends north-northeast with down-to-the basin separation and throws typically of about 100 ft (fig. A-9). Faults having other orientations and smaller throws are also present.

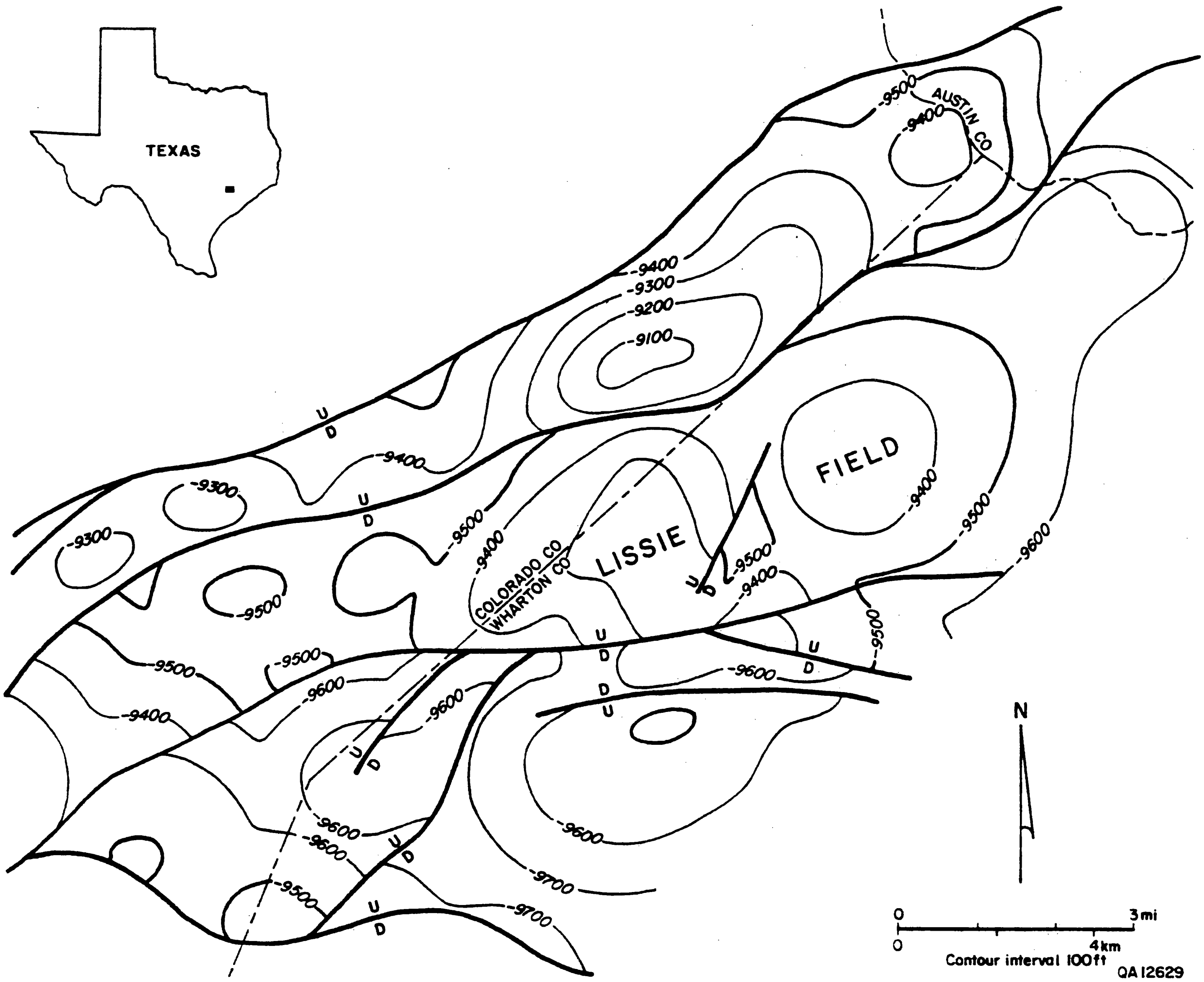

Figure A-9. Structure on top of Wilcox Group, Lissie field, Wharton County. From Geomap.

The two main fault systems create an anastomosing map pattern that is characteristic of the growth-faulted areas of the Gulf Coast Basin. This characteristic structural style is probably modified by structural overprint associated with the evacuation of Mesozoic salt in the salt-dome area of the Houston embayment. Structural patterns are simpler at shallower depths.

Stratigraphic Framework and Sandstone Distribution

Wilcox and Miocene sandstones are the principal reservoirs in the field. The Wilcox Group in this area was deposited in the Rockdale delta system (Fisher and McGowen, 1969) (fig. A-2). The lower Wilcox contains fluvial-dominated deltaic deposits, whereas upper Wilcox sandstones were deposited in a wave-dominated delta system. Thus, different sand-body geometries are expected at different levels within the Wilcox Group. The Miocene sandstones were deposited in the Moulton/Pointblank streamplain system (Galloway and others, 1982) (fig. A-4). Small intrabasinal streams deposited stacked channel sands and overbank sheet and crevasse splay sands. Mostly muds were deposited between stream courses.

Numerous opportunities exist for facies heterogeneity in both Wilcox and Miocene reservoirs. However, complex faulting of Wilcox deposits in Lissie field makes the distinction between stratigraphic and structural reservoir compartmentalization difficult.

Hydrocarbon Production

The field has produced approximately 96 Bcf of gas from five reservoirs through 1986 (table A-3). The Wilcox 9600 sandstone is the principal reservoir. It has produced about 76 Bcf, or 79 percent of the total production, from 12 wells, 7 of which were inactive by the end of 1986. The Miocene 2440 sandstone is the second largest gas-producing interval, accounting for about 20 percent of the total production. The reservoir was drained by 16 wells that were

Table A-3. Production data, Lissie field, Wharton County.

Reservoir name	Depth (ft)	Cum. prod. (MMcf)	Initial BHP/Z	Year first produced	Status
Miocene 2440	2,450	18,923.6	2,150	1961	abd 1972
Frio 3900	3,915	90.9	2,241	1980	abd 1983
Gose 4200	4,200	96.0	2,128	1967	SI
Yegua 6300	6,405	868.7	2,956	1954	abd 1972
Wilcox 9600	9,600	75,965.3	4,958	1949	

abd: abandoned; SI: shut-in

plugged and abandoned in 1972. One Yegua and two Frio reservoirs, all currently inactive, each have contributed 1 percent or less of the total field production.

Recent Activity

No current drilling activity has been noted for the field.

Sheridan Field, Colorado County

Sheridan field, discovered in 1940, is located in west-central Colorado County, about 85 mi southwest of Houston (fig. 2), in RRC district 3. The field, which covers approximately 23 mi^2 miles, was discovered using surface mapping and reflection seismic surveys. The prospect was proved out in 1940 by the successful completion of the Shell Oil Company Plow Realty Company No. 1 well in the Wilcox B sandstone (Lofton, 1962).

Geologic Setting

The field is located along the northeast flank of the San Marcos arch, in the Houston embayment, and forms part of the WX-1 play. The Wilcox growth-fault zone trends to the northwest of the field (fig. 2).

Structure

Sheridan field structure is a rollover anticline related to the Wilcox growth-fault zone. Wilcox intervals show at least 400 ft of vertical closure. The northwest anticline limb is faulted out by elements of the Wilcox fault zone (fig. A-10). The throw and lateral continuity of faulting diminish at shallower depths.

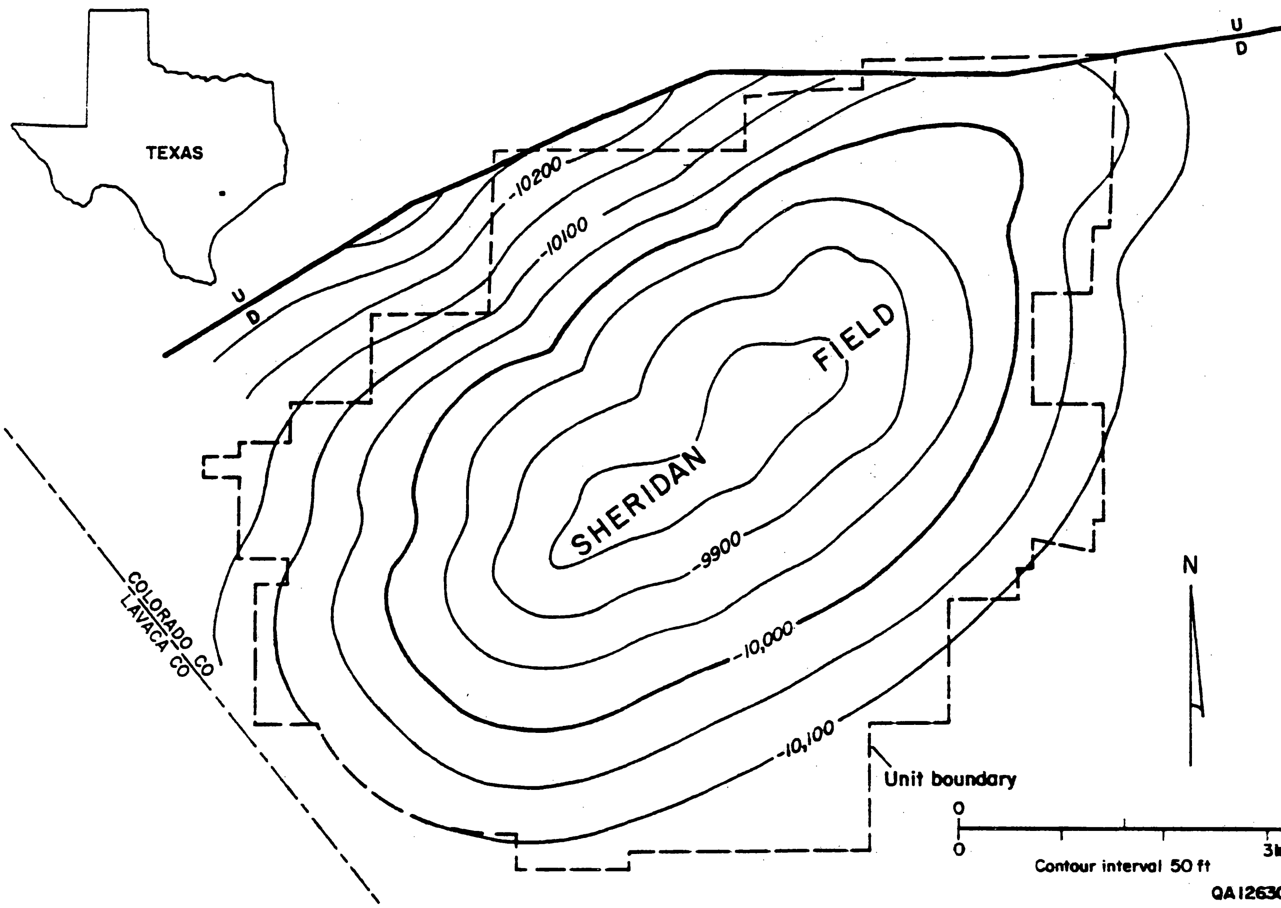

Figure A-10. Structure on top of a "deeper" Wilcox sandstone reservoir, Sheridan field, Colorado County. From Geomap.

Stratigraphic Framework and Sandstone Distribution

Major productive intervals in the field are sandstones in the Wilcox Group (fig. A-2), which in this area form part of the Rockdale delta system. The "deeper" Wilcox is composed of 100- to 200-ft-thick progradational units each having 20- to 50-ft-thick blocky sandstones at the top. These units probably represent vertically stacked, constructional deltaic deposits. The upper Wilcox contains 50- to 75-ft-thick sandstones probably representing channel-mouth-bar deposits that grade up into 50-ft-thick channel-fill and 10- to 30-ft-thick crevasse splay deposits.

The Yegua and Frio Formations are also gas productive in the field. The Yegua comprises 20- to 80-ft-thick coarsening-upward intervals. Each interval is capped by 5- to 10-ft-thick sandstones having laterally limited continuity. The Frio in the Sheridan field was deposited in the Choke Canyon/Flatonia streamplain system and mainly consists of floodplain and lacustrine facies (fig. A-3).

Hydrocarbon Production

Through 1986, approximately 100 Bcf of gas was produced from 23 reservoirs ranging in depth from 3,375 to 13,750 ft (table A-4). The upper Wilcox is somewhat more productive than the "deeper" Wilcox. Gas production from Yegua and Frio reservoirs is comparatively minor, but it only commenced in the late 1960's.

Porosity and permeability have been described as "fair" for the "deeper" Wilcox reservoirs, which lie mostly in the geopressured zone, and "good" for the upper Wilcox. Because most sandstones are calcareous, standard completion practices include acid treatments. Fracture treatments following acid treatments are uncommon.

Table A-4. Production data, Sheridan Field, Colorado County.

Reservoir name	Depth (ft)	Cum. prod. (MMcf)	Initial BHP/z	Year first produced	Status
Frio 3300	3,375	126.4	1,607	1978	
Yegua 5000	5,000	422.9	2,594	1968	abd 1970
Yegua	5,150	133.1	na	1981	abd 1986
Yegua Q	5,290	775.1	2,595	1968	inactive
Yegua S	5,685	312.8	2,196	1979	inactive
Yegua T	5,760	170.5	na	1967	abd 1979
Wilcox A-A5	8,075	1,435.2	3,656	1968	abd 1970
Wilcox B	8,190	361.9	3,734	1963	abd 1968
Wilcox C	8,450	4,201.2	3,772	1963	abd 1968
Wilcox D	8,670	424.9	3,577	1963	inactive
Wilcox H	9,060	42,657.7	3,508	1963	
Wilcox 9300	9,385	5,830.8	4,225	na	abd 1950
Wilcox L	9,340	160.3	4,225	1949	abd 1960
Wilcox	9,700	1,522.6	3,983	1949	
Wilcox O	9,945	739.2	4,046	1949	abd 1971
Wilcox P-P1	9,975	5,079.0	3,876	1961	inactive
Wilcox R	10,275	29.9	3,411	1958	SI 1958
Wilcox 10000	10,350	0.4	na	na	inactive
Sheridan R	10,700	33,787.2	4,405	1952	abd 1961
Wilcox S	11,055	9.3	2,419	1978	abd 1979
Mott	13,385	1,102.3	7,024	1962	abd 1966
Wilcox A-A	13,750	188.8	na	1965	abd 1966

abd: abandoned; SI: shut-in; na: not available

Recent Activity

No recent operator activity is known in the field.

Portilla Field, San Patricio County.

Portilla field is located 5 mi northeast of Sinton, in north-central San Patricio County, in RRC district 4 (fig. 2). It covers approximately 7 mi^2. The field was discovered in 1950.

Geologic Setting

Portilla field lies downdip (east) of the Vicksburg fault system and approximately 15 mi updip (west) of the Frio fault system. It is localized by a rollover anticline on the downthrown (east) side of a growth fault (fig. A-11). The anticline, which trends approximately east-west, is also related to a smaller growth fault just south of the field. The faults remained active throughout Frio deposition and into the early Miocene. Uppermost Frio strata are offset 800 to 1,000 ft across the fault.

Gas reservoirs in the field form part of the Frio FR-7 play. The field contains two Frio barrier-bar/strandplain reservoirs, the 7300 and 7400 sandstones (table A-5). Portilla field also produces from Miocene play MC-1. The field is located near the north end of the play, near the transition with the Matagorda barrier-bar/strandplain system (fig. A-4).

Stratigraphic Framework

The Vicksburg Formation is about 1,500 ft thick at Portilla field, lying at depths ranging from approximately 9,000 ft to 10,500 ft. Vicksburg reservoirs display serrate, funnel-shaped

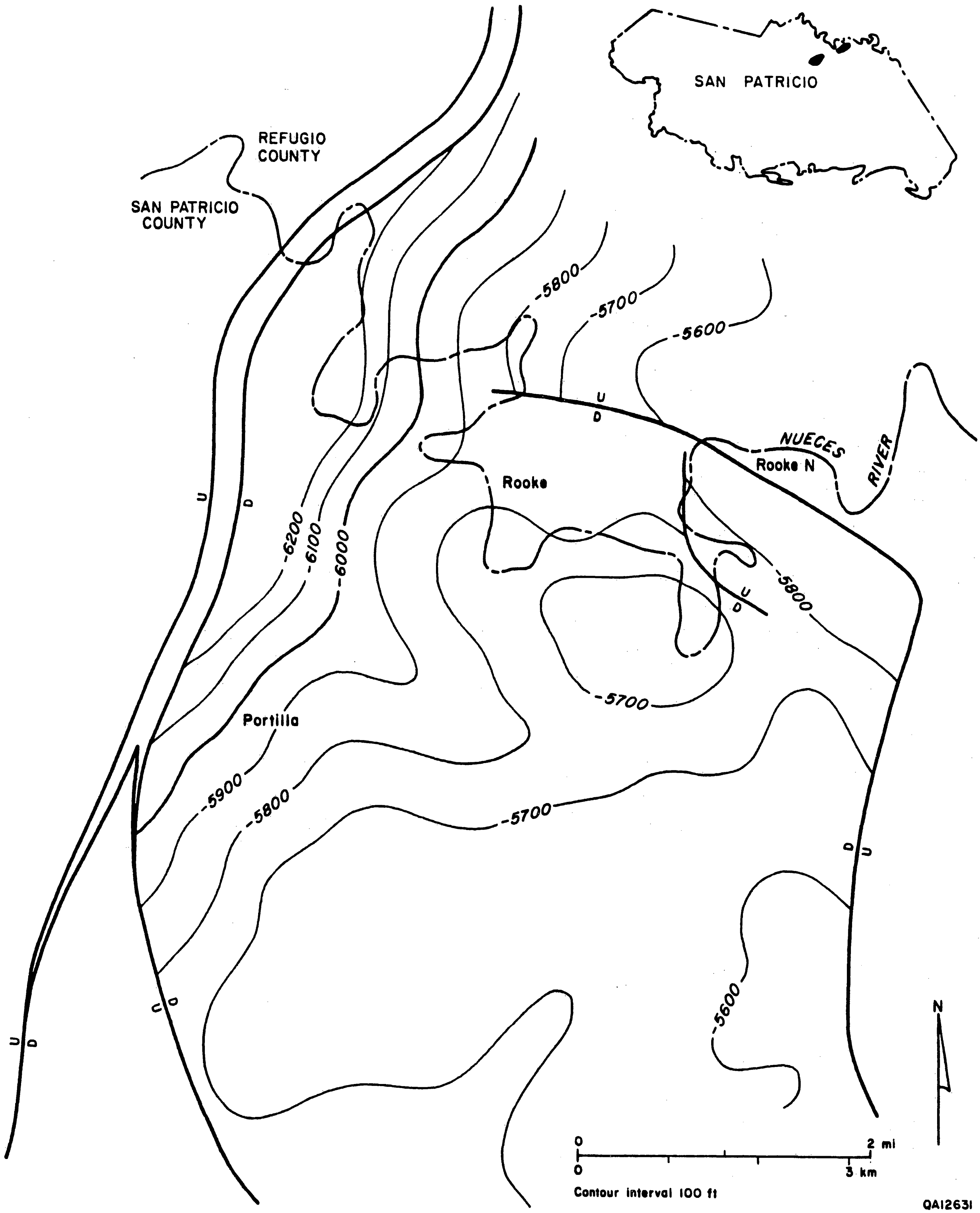

Figure A-11. Structure on top of the *Heterostegina-Marginulina* zone at the top of the Frio Formation, Portilla and Rooke fields, San Patricio County. From Geomap.

Table A-5. Production data, Portilla field, San Patricio County.

Reservoir name	Depth (ft)	Cum. prod. (MMcf)	Initial BHP/Z	Year first produced	Status
3600 A Miocene	3,626	7,365	na	1953	abd 1972
3600 Miocene	3,607	6,544	1,620	1959	
3100 Miocene	3,155	3,166	1,536	1958	abd 1972
4000 Miocene	3,956	2,760	1,963	1964	
3800 Miocene	3,767	2,636	1,783	1954	
3500 Miocene	3,496	967	1,701	1971	
3600 B Miocene	3,643	328	1,802	1955	
3700 Miocene	3,692	232	1,731	1976	
3870 Miocene	3,867	97	1,434	1976	
4050 Miocene	4,068	42	na	1986	
Frio 20	7,060	2	21,042	na	abd 1978
Frio 7050	6,602	1,946	2,779	1973	
Frio 19	7,047	1,943	na	1976	
Frio 7700 C	7,738	211	3,290	1985	
Frio 5700 Stray	5,723	93	2,423	1971	abd 1976
Frio 8500	8,513	43	na	1986	
Frio 7000 B	7,009	27	3,162	1984	abd 1985
Frio 7100	6,207	11	na	1961	abd 1961
Vicksburg 9000	8,821	2,025	3,614	1982	

na: not available; abd: abandoned

well log curves that suggest upward-coarsening, prograding shelf or shoreface deposits. Reservoirs within this section are probably fairly continuous laterally.

The Frio Formation is 4,500 ft thick and consists of stacked progradational and aggradational strandplain and barrier-bar facies. It is overlain by the *Heterostegina* and the *Marginulina* sandstones. Well logs reveal thick, massive sandstones having funnel-shaped (upward-coarsening) and bell-shaped (upward-fining) patterns within the lower Frio, indicative of aggrading strandplains. The upper Frio is less sand-rich and contains several serrate, upward-coarsening packages (the 5700 sandstone) and massive thick sandstones such as the Greta, which is not a gas producer in the field. The thick aggradational barrier-bar/ strandplain sandstones are notably continuous and homogenous. Potential for reservoir compartmentalization is greatest on the updip margins of the system, where lagoon facies can form permeability barriers.

Miocene deposits are about 4,000 ft thick in this area. A thick sand-poor interval lies at the base of the Miocene. It is overlain by an interval containing thin sandstones of probable fluvial origin that display blocky (massive) and bell (upward-fining) log shapes. These sandstones probably form laterally discontinuous reservoirs, as suggested by the numerous reservoirs located at nearly the same elevations within the Miocene section. This interval probably has the best potential for untapped reservoir compartments within the field. The dip orientation of the fluvial channel sandstones and heterogeneities within the fluvial system should create numerous compartments.

Hydrocarbon Production

Portilla is both an oil and gas field. Multiple-stacked reservoirs have produced more than 51 Bcf of gas from more than 60 wells as of the end of 1986 (table A-5). The field contains 19 gas reservoirs, 10 of which are in Miocene strata, 8 in the Oligocene Frio Formation, and 1 in the Vicksburg Formation.

The Frio Formation is the most important producer of both petroleum and natural gas in the field. Eight gas reservoirs account for more than 25 Bcf of gas, or 49 percent of the field production. The most important gas reservoir is the 20 sandstone, which has produced 41 percent of the fieldwide gas and 83 percent of the Frio natural gas.

The 10 Miocene reservoirs, which lie at depths ranging from 3,100 ft to 4,000 ft, have produced 47 percent of the fieldwide natural gas (table A-5). The 3600 and the 3600 A sandstones are the most important reservoirs; together they account for almost 14 Bcf or 27 percent of the total gas production.

There is only one gas reservoir (the 9000 sandstone) in the uppermost Vicksburg Formation. It has produced 2 Bcf, or 4 percent, of the gas in the field.

Recent Activity

Mobil Exploration and Producing U.S., Inc., completed the Welder Minnie S No. 76 well in the Vicksburg Formation in January 1989. It tested (IFD) 16,000 MCFPD from the 7100 reservoir at the depth of 7,052 ft. Acid was used to stimulate the 20-ft-thick producing horizon. The bottom-hole shut-in pressure suggests that the 7100 reservoir is not at virgin pressure. Another well completed by MEPUS in 1988 tested (IFD) 12,850 MCFPD from the 7100 reservoir.

Rooke Field, San Patricio County

Rooke field is located in north San Patricio County north of Portilla field, in RRC district 4 (fig. 2).

Geology

The field lies downdip (east) from the Vicksburg fault zone (fig. A-11). It is a small anticline related to a northwest-southeast-trending fault. Stratigraphy of the field is similar to that of Portilla field, and production is from approximately the same stratigraphic levels in the Frio Formation.

Hydrocarbon Production

The field contains six reservoirs (table A-6). The 7100 A sandstone has produced more than 60 Bcf of gas and is the only reservoir currently producing.

Recent Activity

Marathon Oil Company completed two wells in Rooke North field in 1988. Completion intervals are in the Frio Formation at depths of approximately 7,000 ft.

White Point East Field, San Patricio County

White Point East field is located in south San Patricio County, about 10 mi northwest of Corpus Christi (fig. 2). The field encompasses approximately 11 mi^2, its southern limits extending into the state waters of Nueces Bay. The field was discovered in 1938 with the drilling of the Plymouth Oil Company Brigham 1 well, which was completed as an oil producer from the Frio Brigham Sand at a depth of 5,653 ft.

Table A-6. Production data, Rooke field, San Patricio County.

Reservoir name	Depth (ft)	Cum. prod. (MMcf)	Initial BHP/z	Year first produced	Status
Rooke 6100	6,200	2,510.2	na	1966	abd 1970
Rooke 6700	6,722	1,211.0	2,696	1954	abd 1972
Rooke 6980	6,967	358.4	3,058	1971	abd 1981
Rooke 7100	7,136	49.7	na	1974	abd 1975
Rooke 7100 A	7,026	60,456.2	3,422	1952	
Rooke North 6900	6,973	17.6	3,429	1980	abd 1980

na: not available; abd: abandoned

Geologic Setting

The Frio fault zone lies approximately 2 mi northwest of the field. The field forms part of Frio play FR-6 and Miocene play MC-1.

Structural Framework

The field structure is a faulted, northeast-southwest trending, rollover anticline (fig. A-12) on a downthrown block of the Frio growth-fault zone. The structure is segmented by several discontinuous down-to-the-Gulf normal faults that have more limited throw than does the primary Frio fault, and by antithetic faults showing up-to-the-Gulf separation. Faulting becomes more intense with depth so that the Miocene section exhibits fewer faults with less throw than does the "deeper" Frio section. Structures within this particular part of Frio play FR-6 are noted for complex strain patterns associated with shale ridge growth.

Stratigraphic Framework and Sandstone Distribution

The "deeper" Frio consists of 150- to 200-ft-thick, mud-rich progradational packages that were probably deposited offshore in a shelf setting. Individual sandstones are 2 to 5 ft thick, and they probably have relatively good lateral continuity. The middle and upper Frio are composed of 25- to 150-ft-thick sandstones that are characteristic of the Frio FR-6 play. Sandstone bodies within this play are strike-elongate, sand-rich, upward-coarsening units deposited in the Greta/Carancahua barrier-bar/strandplain system (fig. A-3). Upward-fining, 50-ft-thick units are less common and likely represent tidal-channel or inlet fills. Stacking patterns that are aggradational in character in the middle Frio grade upward into shelf mudstones and sandstones, suggesting at least a local, short-lived transgressive episode. This finer grained

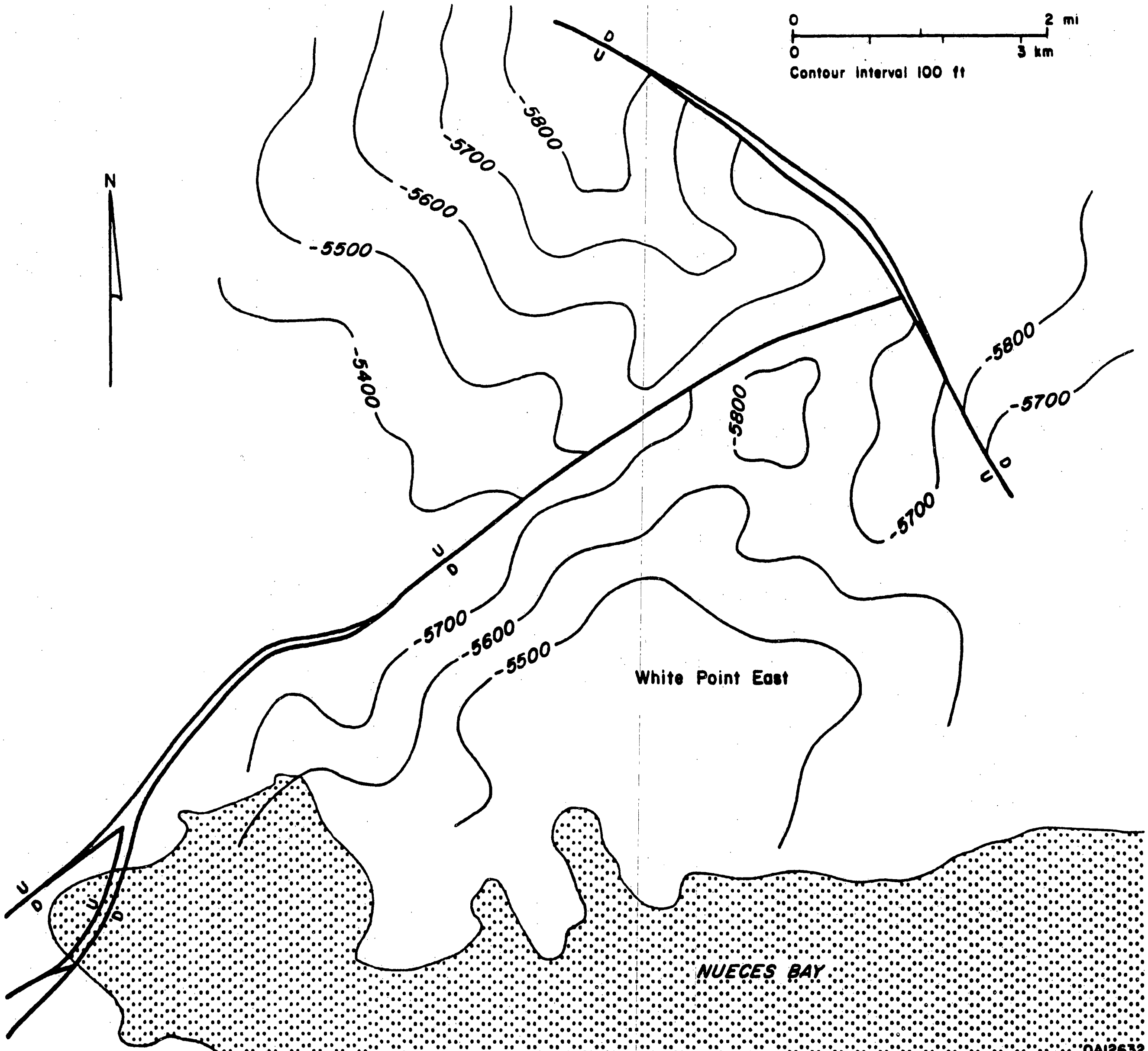

Figure A-12. Structure on top of a horizon in the upper Frio, White Point East, Nueces County. From Geomap.

section is part of the *Heterostegina-Marginulina* interval, or upper Frio sandstones. Well logs in the upper Frio show funnel-shaped (upward-coarsening) patterns at the base and bell-shaped (upward-fining) patterns at the top where the retrogradational upper Frio grades upward into the lower Anahuac Shale.

Reservoirs in the field were deposited at the boundary of fluvial, deltaic, and barrier-bar/strandplain depositional systems through the Miocene (figs. A-4, A-5). Although the overall upward trend suggests sustained progradation, localized transgressive episodes resulted in major landward shifts in the position of depositional systems tracts. The lower Miocene deposits include 50-ft-thick, coarsening-upward intervals and 25- to 50-ft-thick, sand-rich channel-fill deposits. The Matagorda barrier-bar/strandplain system was also near the position of White Point East field. The middle and upper Miocene are represented by deposition in lagoonal facies of the Mustang barrier-bar and the Realitos fluvial systems. Bed- and mixed-load channel-fill sandstones of the Realitos system in the White Point East area are vertically stacked, channel-fill sandstones that generally do not exceed 30 ft in thickness.

The opportunity for reservoir compartmentalization is highest in the Miocene section. The Frio contains vertically stacked barrier-bar/strandplain sandstones that likely have a high degree of both vertical and horizontal connectivity. The Miocene, on the other hand, includes a thick section of fluvial deposits that are stratigraphically heterogeneous. The "deeper" Frio may be another candidate for reservoir compartmentalization; however, little is known about the geometries of these particular shelf sandstones. Also, this part of the section is further complicated by numerous faults and lies within the geopressured zone.

Hydrocarbon Production

The field produces gas from upper Frio and Miocene sandstones. Cumulative gas production through 1985 was more than 381 Bcf from 84 reservoirs. The largest number of reservoirs (31) and greatest cumulative production (59 percent) are found in uppermost Frio, retrogradational *Heterostegina* sandstones and in the lower Miocene. The remaining reservoirs are subequally divided between the middle Frio and middle and upper Miocene. The remaining gas production, however, is subequally proportioned between the "deeper" Frio, middle Frio, and middle and upper Miocene. The "deeper" Frio has contributed 11 percent of the fieldwide gas production from five reservoirs and has been developed over about the last 15 years. Thus, these "deeper" Frio shelf sandstones are promising candidates for infield reserve growth. Table A-7 presents data from reservoirs that have produced more than 10 Bcf of gas and those discovered since 1980.

Recent Activity

Mobil Exploration and Producing U.S., Inc., was the only operator drilling in the field in early 1989. The Rachal No. 81 well bottomed at 11,398 feet and tested the Miocene (3,210-3,213 ft and 3,262-3,265 ft), upper Frio (4,771-4,774 ft) and "deeper" Frio (11,250-11,360 ft). Scout reports suggest only weak gas production potential from the Miocene (520 MCFPD through a 14/64-inch choke).

Stratton-Agua Dulce Fields, Nueces, Kleberg, and Jim Wells Counties

Stratton and Agua Dulce are both oil and gas fields in RRC district 4. Stratton field is located at the junction of Jim Wells, Kleberg, and Nueces Counties, along San Fernando Creek, about 8 mi northwest of Kingsville. Agua Dulce field is located to the northwest in Nueces County (fig. 2). The combined name Stratton-Agua Dulce is used for these fields in this compilation because they are contiguous and their geological and production characteristics are generally similar. Data were compiled for Stratton field, which covers an area of approximately 60 mi^2. The field was discovered in 1937, when production was established in the Stratton

Table A-7. Production data, White Point East field, San Patricio County.

Reservoir name	Depth (ft)	Cum. prod. (Bcf)	Initial BHP/Z	Year first produced	Status
4807	4,700	0.000	2,208	1986	
3350	3,200	0.002	1,562	1981	
3650	3,600	0.007	1,650	1985	
5970	5,900	0.010	2,884	1983	abd 1985
MEEP	5,700	0.013	2,393	1981	abd 1985
Het 4600	4,600	0.031	na	1983	abd 1985
5800 Seq B	5,700	0.031	2,694	1981	
5800 Stray	5,700	0.041	2,500	1984	abd 1984
Cole Sand	6,700	0.044	na	1985	
5350	5,300	0.066	2,647	1982	
Greta 4900 NW	4,800	0.084	na	1985	
3000	3,000	10.250	1,450	1954	
French	11,000	10.520	6,529	1976	
3700	3,600	12.500	na	1955	
Copeland	11,800	13.800	6,744	1974	
Edonce	11,800	15.603	6,821	1978	
4800	4,800	18.040	na	1952	abd 1959
White Point 2500 N	2,500	21.134	1,111	1957	
3100	3,100	21.290	1,623	1951	
3800	3,700	22.852	1,936	1953	
White Point 2500	2,400	28.610	797	1955	
White Point 3900	3,800	47.549	1,874	1951	
4000	4,000	65.996	1,839	1951	

na: not available; abd: abandoned

(Comstock) reservoir. More than 270 Frio and Vicksburg reservoirs have been identified and more than 1,000 wells have been drilled in the field.

Geologic Setting

The fields are located in the Rio Grande embayment along the downdip margin of the Vicksburg fault zone. They are included within plays Frio FR-4 and Vicksburg VK-1. Frio strata are generally only mildly affected by Vicksburg growth faulting. Gentle folding into rollover anticlines and some faulting (primarily in the lower Frio) are the result of movement along Vicksburg faults. Vicksburg strata, however, are greatly affected by the fault zone, thickening tremendously across the fault. Structural complexity increases with depth, but is not significant at middle Frio depths.

Structural Framework

Stratton field is an anticline bounded updip by a large northeast-southwest-trending growth fault that offsets lower Frio strata several hundred feet. The east, downdip boundary is not clearly defined at the point where the field merges with Stratton East and other fields. Within the field, subsidiary highs occur on the primary rollover anticline that traps hydrocarbons. Lower Frio structure is affected by moderate faulting, especially at depths greater than 6,500 ft. The Vicksburg is intensely faulted.

Stratigraphic Framework and Sandstone Distribution

The Vicksburg-Frio boundary is not well defined in Stratton field. Well logs from wells penetrating Vicksburg strata (generally below 7,000–7,500 ft) indicate a generally sand-poor interval from depths as great as 8,000 ft. A sand-rich section exhibiting thick, funnel-shaped (upward-coarsening) and blocky log patterns stretches from about 8,000 ft to the top of the Vicksburg Formation (fig. A-13).

The fields are located at the downdip edge of the Gueydan fluvial system, near the Norias delta system and adjacent Greta/Carancahua barrier-bar/strandplain system (fig. A-3). Vicksburg deposits in Stratton field probably are deltaic depositional systems. Dip-elongate sandstones of the lower Vicksburg are generally interpreted as deposits of fluvially-dominated, lobate deltas. Strike-elongate sandstones of the middle and upper Vicksburg are interpreted as deposits of wave-dominated, cuspate deltas. The Frio section in Stratton field is typified by 10- to 50-ft-thick sandstones interbedded with shales. Log patterns are dominantly bell shaped (upward-fining) to blocky, and sandstone bodies are lenticular (fig. A-13), suggesting fluvial depositional environments.

Trapping mechanisms in Stratton field appear to be a combination of structural and stratigraphic types. Gas accumulations are found on the crests of faulted anticlines, especially in the lower Frio and Vicksburg sections. In the shallower section, faulting is minimal and does not provide the fault closures found at depth. Sandstones in the middle and upper Frio are lenticular and discontinuous, providing an excellent setting for stratigraphic traps within the rollover anticline. Because Frio sediments in the field were deposited in primarily fluvial environments, stratigraphic traps due to facies changes and sandstone pinch-outs cause significant gas accumulations.

The Frio section in Stratton field is normally pressured, but the deeper reservoirs in the field are geopressured. The approximate top of geopressure in the area falls in the 7,000- to 8,000-ft depth range, which is probably at or near the top of the Vicksburg Formation. Porosity and permeability data were unavailable for wells in Stratton field, although analysis of whole-core samples from middle and upper Frio reservoirs in the nearby Seeligson field (Jim Wells and Kleberg Counties) indicates a wide range of environment-dependent values, permeabilities ranging from 60 to 1,100 md and porosities ranging from 19 to 27 percent. Although reservoir quality in Stratton field would be expected to be generally good, particularly in the middle and

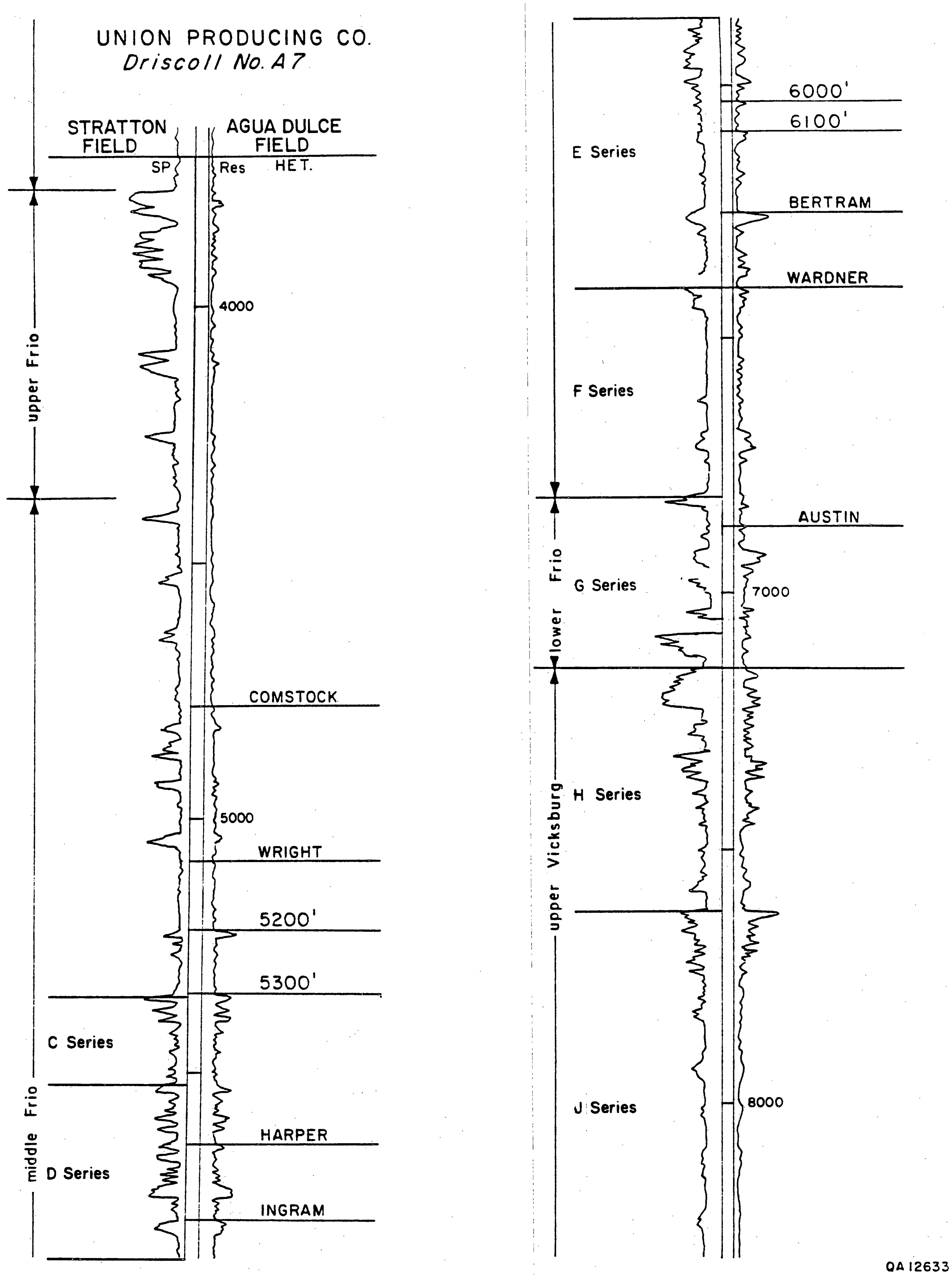

Figure A-13. Well log showing gas reservoirs in Stratton and Agua Dulce fields, Jim Wells, Kleberg, and Nueces Counties.

upper Frio section, hydraulic fracture stimulation treatments are occasionally employed. These treatments are small, however, and generally use 10,000 to 55,000 lb of sand.

Hydrocarbon Production

Stratton field has produced approximately 2.6 Tcf of gas from more than 270 Frio and Vicksburg reservoirs ranging in depth from 1,500 to 9,000 ft. Forty-four reservoirs have produced more than 10 Bcf each. The largest producer is the Wardner reservoir, which has a cumulative production of approximately 336 Bcf (table A-8). Simplified production decline plots for the Stratton (Wardner) reservoir illustrate a significant increase in annual production since 1986, reflecting an infill drilling program conducted by Union Pacific Resources that probably tapped undrained reservoir compartments. Table A-8 presents production data for Stratton field. It contains data for those reservoirs having cumulative productions of more than 10 Bcf and those discovered since 1980.

Recent Activity

Union Pacific Resources (UPR) was very active in Stratton field during the last quarter of 1988 and in early 1989. During that time drilling and completion activities by Pennzoil, which operates most of the Agua Dulce field, were low. By the end of the first four months of 1989, UPR had completed 19 wells (14 dual completions), was drilling 22 wells, and had staked 5 new locations. The G series reservoirs were targeted most frequently, with 16 completions. The F series had 13 completions, the E series had 2 completions, and the H and K series (fig. A-13) had one completion each.

Fifteen of the late 1988 completions were new pool discoveries (13 gas, 2 oil). Reported calculated absolute open gas flow rates (CAOF) range from 54 MCFPD to 33,000 MCFPD; the highest flow is from the Frio G-21-9 reservoir. Six of the recent completions in the G series,

Table A-8. Production data, Stratton field, Nueces, Kleberg, and Jim Wells Counties.

Reservoir name	Depth (ft)	Cum. prod. (Bcf)	Initial BHP/z	Year first produced	Status
A-5300	5,200	61.1000	2,344	1949	
Arroyo A-6700	7,000	22.7000	3,897	1955	
Austin, upper	680	34.8000	3,767	1949	
Austin, West middle	6,600	94.9000	3,189	1950	
Austin, West upper	6,500	157.5000	3,668	1949	
B-5300	5,200	27.5000	2,782	1949	
Bertram	6,300	227.2000	2,903	1950	
Bertram A	6,400	0.1000	3,797	1986	
Bertram North	6,200	10.8000	2,815	1951	
Bertram So	6,200	46.2000	na	na	
Bertram W	6,000	112.3000	3,103	1949	
C-35-3	5,200	0.0500	na	1984	
Comstock	4,700	167.7000	2,408	1949	
Comstock-B 4700	4,700	18.1000	2,383	1949	
D-20	5,400	0.3000	na	1984	
D-26-2	5,500	0.2000	2,474	1984	
D-35-3E	5,700	0.1000	na	1986	
D-49	5,600	20.4000	2,669	1959	
D-49-1	5,800	0.0900	na	1986	
E-18-3	5,900	0.2000	2,349	1983	
E-25	5,800	20.7000	3,151	1955	
E-31	6,000	19.6000	2,934	1959	
E-31-6	6,100	0.3000	2,373	1983	
E-31-7	6,100	0.2000	na	1984	
E-41-4	6,300	0.8000	na	1984	
E-49-13	6,400	0.0006	2,402	1980	abd 1985
F-16-4	6,400	0.0100	2,625	1982	abd 1986
F-22	6,700	1.6000	1,053	1980	
F-25-1	6,500	0.0700	2,706	1986	
F-28	6,600	11.6000	3,027	1960	
F-31-1	6,600	0.8000	3,160	1983	
F-31 Res 11	6,600	2.4000	3,540	1981	
F-31-12	6,600	1.0000	3,588	1982	
F-39	6,700	29.4000	3,577	1952	
F-39-10	6,800	13.0000	3,735	1954	
F-39-11	6,800	0.5000	969	1982	
F-39-14	6,800	2.2000	3,614	1982	
F-44 Res 7	6,900	1.0000	3,719	1980	abd 1983
G-00	7,000	0.0900	na	1984	
G-2-2	7,200	0.2000	4,065	1982	abd 1983
G-00 SW	6,900	0.1000	4,280	1983	

Table A-8 (cont.)

Reservoir name	Depth (ft)	Cum. prod. (Bcf)	Initial BHP/z	Year first produced	Status
G-2 Res 6	7,000	0.0300	3,637	1981	abd 1983
G-9-4	7,000	0.4000	na	1983	
G-9 Res 7	6,900	0.2000	3,382	1980	
G-9 Res 8	6,900	0.9000	4,330	1981	
G-9-9	7,100	0.5000	3,900	1982	
G-9 Res 10	6,900	0.6000	2,797	1982	
G-9 Res 12	6,800	0.0500	na	1985	
G-9 Res 13	7,200	0.0700	4,236	1986	
G-15-2	6,900	0.1000	3,935	1982	
G-17	7,100	0.6000	4,045	1981	
G-21-5	7,200	4.2000	3,570	1982	
G-21-6	7,000	0.1000	3,719	1982	
G-21 Res 4	7,200	2.3000	4,086	1981	
G-24	6,200	0.0400	3,415	1983	
G-29 Res 2	7,300	1.3000	4,101	1981	abd 1985
G-29-4	na	0.0080	na	1982	abd 1983
G-29-5	7,400	0.3000	4,081	1986	
Goliad	500	0.4000	38	1981	
H-10	7,100	0.0600	4,108	1981	abd 1984
H-23 Sand	7,300	0.1000	3,539	1981	SI 1986
H-29-2	7,300	0.0100	na	1984	abd 1984
H-37 Res. 2	7,400	1.8000	4,097	1981	
Het, Lower	4,000	66.5000	2,203	1952	
H-45	7,400	0.1000	na	1984	abd 1986
H-55	7,500	0.0600	na	1981	abd 1984
J-2 Res 1	7,600	0.0900	4,735	1981	
J-8	7,600	0.2000	na	1984	
J-10	7,500	12.6000	4,89	1952	
J-42	7,900	0.0700	4,929	1981	abd 1983
Juan	5,600	18.8000	na	1965	
K-41	8,200	0.3000	5,566	1982	
L-4	6,100	61.6000	3,287	1953	
L-5-2	8,400	0.9000	na	1984	
L-16 L	6,200	0.2000	2,889	1981	
N-23 NC	6,500	0.1000	1,626	1981	
C-28 S	6,700	0.0080	3,090	1983	abd 1984
N-26 E	6,600	0.0010	1,058	1983	
N-26 SW Seg 2	6,700	0.0800	3,251	1981	abd 1984
N-28 W-2	6,600	0.3000	3,804	1982	abd 1985
P-4 C	6,700	0.6000	2,644	1984	
P-4 W	6,700	0.2000	3,052	1982	abd 1986

Table A-8 (cont.)

Reservoir name	Depth (ft)	Cum. prod. (Bcf)	Initial BHP/z	Year first produced	Status
P-5	6,900	12.4000	3,691	1958	
R-2	6,900	0.0900	3,476	1984	
R-2 L	6,800	13.1000	2,571	1973	
R-2 S	6,800	0.2000	3,387	1983	
R-5 6750	6,800	41.7000	3,820	1953	
R-13	6,800	18.3000	3,100	1964	
Res 3 G-15	6,900	0.1000	3,377	1986	
Rivers Lower	5,500	22.2000	na	1965	
Rivers Upper A	5,400	77.1000	2,895	1957	
Rivers Upper B	5,300	53.9000	2,625	1961	
Sellers Upper	6,300	12.2000	3,006	1953	
Sellers Upper Gas	6,100	10.8000	3,259	1954	
Sellers I	6,100	0.0100	3,217	1981	abd 1981
Sellers 4 Lower	6,300	0.0300	1,096	1980	abd 1981
VXS T-7	7,200	0.0050	3,865	1985	
W-67	6,700	17.9000	3,776	1960	abd 1974
W-69	6,700	14.0000	3,740	1960	
W-92	6,900	24.4000	4,407	1960	
W-92-3	7,300	0.7000	4,247	1982	abd 1984
Wagner	7,100	25.5000	4,407	1958	SI 1960
Wardner	6,500	336.6000	2,308	1949	
Wardner West	6,100	90.3000	2,670	1949	
Wardner 2 Up.	6,300	24.2000	2,118	1955	abd 1981
Zone H-37 S	7,300	0.1000	4,092	1986	
4300	4,200	11.2000	1,869	1968	
4900	4,800	37.1000	2,450	1950	
5000	5,000	136.8000	2,483	1949	
5100	4,900	32.8000	1,790	1952	
5200	5,100	45.9000	2,278	1954	
5800	5,600	24.0800	2,865	1958	
6070	6,000	0.0050	2,890	1982	abd 1983
6200	6,100	0.4000	na	1984	
7730	7,700	0.0100	na	1984	abd 1984
8200	8,200	0.1000	4,393	1985	
8800	8,800	0.0300	na	1984	

na: not available; abd: abandoned; SI shut-in one in the F series and one in the E series, were fracture stimulated. Bottom-hole shut-in pressures for the new pool discoveries reflect virgin pressures, and near-virgin pressures have been measured in several other development well completions, strongly suggesting reservoir compartmentalization.

Seeligson Field, Jim Wells and Kleberg Counties

Seeligson field covers approximately 50 mi^2 in Jim Wells and Kleberg Counties, about 5 miles north of the town of Premont, Texas, in RRC district 4 (fig. 2). The field was discovered in 1937 when the Magnolia A. A. Seeligson No. 7 well was drilled to a depth of 8,141 ft where hydrocarbons in Zone 22-5 sandstones were encountered. More than 1,000 wells have been drilled in the field. Cumulative gas production exceeds 2.5 Tcf.

Structural Framework

The field is located along the margin of the Vicksburg fault zone. It is bounded updip by a large northeast-southwest-trending growth fault that offsets sandstones of the Frio Formation several hundred feet. The east, downdip boundary is defined by the limits of production. The field structure is a rollover anticline having subsidiary highs.

Stratigraphic Framework and Sandstone Distribution

More than 130 Frio and Vicksburg sandstone reservoirs have been documented across the field. The multiple, vertically stacked, dominantly fluvial sandstones exhibit varying degrees of complexity. Aggregate sandstone patterns illustrate dominantly dip-parallel depositional trends that are generally indicative of fluvial environments. The interbedded sandstones and shales reflect the diversity of environments of deposition within each zone (for example, channel, crevasse splay, flood plain, levee).

Hydrocarbon Production

The field has produced approximately 2.5 Tcf of gas from 131 Vicksburg and Frio reservoirs ranging in depth from 4,000 to 8,500 ft. Twenty-seven reservoirs have produced more than 10 Bcf each. Table A-9 shows data for reservoirs that have produced more than 10 Bcf of gas and for those discovered since 1980. Most of the gas is trapped on the crest of rollover anticlines associated with the major Vicksburg growth fault, but there is a substantial control of lithofacies reservoir architecture (for example, sand-body pinch-outs or facies changes) on the accumulations.

Reservoir quality in Frio sandstones within the field is generally good. Whole core analyses indicate porosities of 19 to 27 percent and permeabilities of 60 to 1,100 md in point-bar and crevasse splay sandstones. Reservoir-stimulation techniques are generally limited to acidizing.

Recent Activity

Oryx Energy Company, the unit operator, has been evaluating recompletion opportunities in a systematic manner across the field during the last three years. Mobil Exploration and Producing U.S., Inc., is conducting a deeper-pool-tests program having non-unit, basal Frio and Vicksburg objectives.

Table A-9. Production data, Seeligson field, Jim Wells and Kleberg Counties.

Reservoir	Depth (ft)	Cum. prod. (Bcf)	Initial BHP/z	Year first produced
Zone 07-F	4,200	0.0800	2,200	1985
Zone 08-A	4,200	16.1000	2,341	1976
Zone 09-B	4,500	16.3000	2,095	1951
Zone 10	4,500	24.7000	2,168	1949
Zone 11-A	4,400	0.1000	2,081	1984
Zone 11-C	4,700	0.3000	2,077	1981
Zone 12-A-06	4,800	12.3000	1,584	1960
Zone 12-B	4,800	19.1000	2,663	1949
Zone 13-A-05	4,900	25.5000	na	1957
Zone 13-B-06	4,900	13.7000	2,652	1950
Zone 14-A	5,000	18.6000	2,430	1970
Zone 14-B	5,100	155.6000	2,212	1958
Zone 14-C-02	5,100	17.3000	2,058	1959
Zone 14-C-06	5,200	16.6000	1,843	1960
Zone 15	5,300	195.9000	2,647	1949
Zone 16-D	5,400	663.1000	2,619	1958
Zone 17	5,400	46.1000	2,838	1949
Zone 17-02	5,500	64.3000	2,759	1949
Zone 17-05	5,500	68.0000	2,306	1950
Zone 18-A	5,600	25.4000	2,815	1950
Zone 18-A-05	5,600	102.6000	2,842	1950
Zone 18-B-02	5,700	12.9000	2,854	1949
Zone 18-C	5,700	21.8000	2,701	1957
Zone 19-B-03	5,900	169.0000	2,418	1958
Zone 19-C	5,800	0.1000	869	1986
Zone 19-C-04	5,700	43.1000	2,672	1959
Zone 19-D-06	na	0.0030	na	1982
Zone 20-A-03	6,000	67.4000	2,618	1957
Zone 20-A-05	5,900	63.5000	2,640	1957
Zone B-20-03	6,000	32.6000	2,649	1957
Zone 20-C-05	6,300	0.8000	1,522	1980
Zone 20-C-15	6,000	46.5000	2,695	1958
Zone 20-C-44	6,000	38.1000	2,714	1958
Zone 20-D-N	6,200	0.6000	na	1981
Zone 20-F	6,100	0.2000	1,585	1981
Zone 20-G-02 N	6,200	0.0600	3,126	1981
Zone 20-G-02-U	6,200	0.0400	3,206	1980
Zone 20-H Central	6,700	0.0400	3,418	1982
Zone 20-H-02 N	6,200	0.5000	2,850	1982
Zone 20-H-02 South	6,300	13.0000	na	1965
Zone 20-I-1	6,600	10.9000	3,791	1974

Table A-9 (cont.)

Reservoir	Depth (ft)	Cum. prod. (Bcf)	Initial BHP/z	Year first produced
Zone 20-I-4 South	6,700	0.0900	3,412	1981
Zone 21-A-01	6,500	77.6000	3,401	1959
Zone 21-C-02	6,700	13.7000	na	1965
Zone 21-C-02 West	6,500	51.0000	4,039	1949
Zone 21-D-SW	6,700	0.4000	1,110	1985
Zone 21-E	6,500	1.8000	939	1980
Zone 21-E N	6,800	0.0100	1,644	1982
Zone 21-G-02	6,500	53.4000	na	1965
Zone 22-C-04	6,900	1.2000	na	1984
Zone 22-K	7,100	0.3000	4,547	1984

na: not available

McAllen Ranch Field, Hidalgo County

McAllen Ranch field encompasses more than 10 mi^2 in northwest Hidalgo County, about 30 mi north of the U.S.-Mexico border and 10 mi north of the town of McCook, in RRC district 4 (fig. 2). The field was discovered in 1960 when the Shell A. A. McAllen No. 1 well was completed as a gas producer. Shell completed a successful development program in which 14 wells were drilled (no dry holes) from late 1960 through 1963. More than 130 wells have been drilled in the field, 33 Vicksburg reservoirs contributing to production.

Structural Framework

Two anticlines localize production in the field. The anticlines are related to growth faults. Structure in the upper Vicksburg is relatively simple: anticlinal noses formed on the downthrown side of a growth fault. Several growth faults and antithetic faults characterize the middle Vicksburg structure. Structure in the lower Vicksburg becomes complicated by additional growth faults and associated faults. Middle and lower Vicksburg faults control elongate closures within the field, and dip reversal becomes more pronounced with depth.

Stratigraphic Framework and Sandstone Distribution

The lower Vicksburg in McAllen Ranch field includes several sandstone-rich intervals as much as 1,000 ft thick displaying funnel-shaped (upward-coarsening) log patterns. Isoliths of the uppermost sandstone package in the lower Vicksburg show dip-elongate depositional axes and a general lobate pattern that suggest distributary channel or channel-mouth-bar deposition. Detailed studies of individual sandstones in McAllen Ranch field have identified one or more distributary-channel systems that terminate in the area. The middle Vicksburg also contains several upward-coarsening sandstone sequences as much as 400 ft thick. Net-sandstone maps of the middle Vicksburg show strike-oriented sandstone trends having a slight cuspate bulge, indicating a possible marine influence or coastal-barrier deposits in a wave-dominated deltaic environment. The upper Vicksburg is characterized by a thick shale section containing only a few thin sandstones that may be distal delta-front sandstones.

Hydrocarbon Production

The field has produced more than 770 Bcf of gas from 33 Vicksburg reservoirs ranging in depth from 7,000 to 15,000 ft. Fourteen reservoirs have produced more than 10 Bcf each. The largest producer is the Vicksburg S, S reservoir, which has a cumulative production of more than 124 Bcf. Table A-10 shows reservoirs having more than 10 Bcf cumulative production and those discovered since 1980. Production decline plots for the McAllen Ranch Vicksburg S, S reservoir document a 5-yr decline, followed by a marked increase in annual production over the next 3 yr, as well as higher BHP/Z values. These increases may be the result of reservoir compartments tapped by new wells.

The complex structural configuration, particularly in the lower Vicksburg, provides numerous fault closures and structural traps. Stratigraphic traps occur where facies changes result in permeability barriers and reservoir compartmentalization.

The entire Vicksburg section has abnormal fluid pressures. The top of geopressure occurs at depths ranging from 7,000 to 8,400 ft. Pressure gradients are as much as 0.94 psi/ft. Fluid pressures tend to increase with depth through the S sandstone and then decrease somewhat through the V and Y sandstone.

Porosity and permeability data from McAllen Ranch field indicate poor reservoir quality. The majority of whole-core samples show permeabilities of less than 1 md, only a small percentage having permeabilities greater than 10 md. Porosities range from about 16 to 25 percent. Because of the generally poor reservoir quality, fracture stimulation techniques are

Table A-10. Production data, McAllen Ranch field, Hidalgo County.

Reservoir name	Depth (ft)	Cum. prod. (Bcf)	Initial BHP/Z	Year first produced	Status
Guerra	14,000	30.013	8,117	1984	
Guerra E	14,100	0.475	na	1986	
Vicksburg L	9,300	14.630	6,491	1962	
Vicksburg P	10,000	113.146	7,096	1963	
Vicksburg Q	8,800	21.749	na	1963	
Vicksburg Q, N	11,300	0.058	na	1985	
Vicksburg R	11,500	21.776	6,778	1961	
Vicksburg R Cent	10,800	31.083	6,856	1962	
Vicksburg S	11,700	87.159	7,315	1964	
Vicksburg S East	11,600	2.903	7,208	1984	
Vicksburg S North	13,400	24.987	na	1966	
Vicksburg S South	11,800	124.366	na	1965	
Vicksburg S SE	11,700	36.042	6,962	1972	
Vicksburg T	12,000	36.280	7,175	1963	
Vicksburg T South	12,100	13.140	na	1966	
Vicksburg U-V SE	12,100	121.634	7,517	1972	
Vicksburg Y	12,700	51.635	7,805	1975	

na: not available; abd: abandoned

used in about half of the completions, sand weights usually ranging from 300,000 to 500,000 lb. However, reservoirs often produce one to several MMCFD of gas before fracture treatment.

Recent Activity

Shell Western Exploration and Production, Inc., was active in McAllen Ranch field in 1988, and by early 1989 it had completed six gas wells, was drilling one well, and had one location staked. Initial potential (IP) tests of 380, 1,500, and 1,550 MCFPD were reported in three wells recently completed in the S reservoir. One well was completed in the McAllen Ranch Vicksburg Q sandstone with an IP of 4,100 MCFPD, one well was completed in the McAllen Ranch Vicksburg 15,300 sandstone with an IP of 585 MCFPD, and one well was completed in the McAllen Ranch Guerra reservoir with an IP of 52,000 MCFPD. Bright and Company was drilling one well and had one location staked. Texaco had one location staked.

Lyda Field, Starr County

Lyda field is located in north Starr County, southeast of Sun gas field, in RRC district 4 (fig. 2). It covers approximately 4 mi^2.

Geology

The geology of the field is similar to that of McAllen Ranch field. Production is from intensely faulted Vicksburg reservoirs.

Hydrocarbon production

The field has produced approximately 19 Bcf of gas. There are 17 reservoirs that are drained by about 25 wells. Eleven reservoirs first produced in the 1980's. The reservoirs lie at depths ranging from 7,000 to 9,500 ft. Table A-11 presents production data for the field.

Recent Activity

Sun Oil Company (now Oryx Energy Company) drilled about two successful development wells per year in the last 3 yr, mostly in the south part of the field. Targets are Vicksburg reservoirs occurring in discrete, isolated fault blocks. Two wells were drilled in 1988, a deeper-pool test (Speer No. 1) well and a development well (Hall No. 10).

Flores and Jeffress Fields, Starr and Hidalgo Counties

Flores and Jeffress fields are located in the vicinity of the boundary between Starr and Hidalgo Counties, in RRC district 4 (fig. 2). Together the two fields cover approximately 14 mi^2. Flores field was discovered in 1945 when Sun Oil Company completed the Flores No. 1 well in Vicksburg reservoirs. Jeffress field was discovered in 1960 when the Sun Oil Company Jeffress No. 2 well produced gas from the Vicksburg T sandstone. Eleven Frio and 31 Vicksburg reservoirs have been identified. Ten of the Frio and 19 of the Vicksburg reservoirs lie only in Flores field, and 7 of the Vicksburg reservoirs are found only in Jeffress field. The remaining Frio reservoir and five Vicksburg reservoirs are common to both fields. More than 100 wells have been drilled.

Table A-11. Production data, Lyda field, Starr County.

Reservoir name	Depth (ft)	Cum. prod. (MMcf)	Initial BHP/z	Year first produced	Status
Rincon-B 8600	8,600	2,191.7	5,080	1957	
Rincon 7460	7,400	92.4	na	1985	
Vicksburg 6350	6,350	77.3	3,015	1971	abd 1978
Vicksburg 6865	6,865	258.1	3,547	1983	
Vicksburg 6940	7,000	259.1	2,533	1977	
Vicksburg 8100	8,100	44.2	4,034	1986	
Vicksburg 8230	8,230	164.8	na	1985	
Vicksburg 8500	8,500	2,896.9	5,052	1959	abd 1971
Vicksburg 8690	8,690	120.5	5,195	1983	abd 1985
Vicksburg 8720	8,720	304.7	5,459	1983	
Vicksburg 8950	9,100	32.2	na	1985	
Vicksburg 9110	9,110	46.8	na	1986	
Vicksburg 9250	9,250	1,755.3	5,802	1984	
Vicksburg 9300	9,300	2,614.1	na	1967	
Vicksburg 9330	9,300	3,042.8	na	1984	
Vicksburg 8900	8,900	2,515.6	5,472	1982	
Vicksburg 9100	8,900	2,820.3	5,382	1959	

na: not available; abd: abandoned

Geologic Setting and Structural Framework

The fields are included in plays Frio FR-4 and Vicksburg VK-1. Flores and Jeffress lie about 5 mi east of the main strand of the Vicksburg fault on the northern noses of two large roll-over anticlines that are cut by numerous faults (fig. A-14). Flores field lies on the downthrown (east) side of a small normal fault. Three anastomosing growth faults cut the west portion of the field. Jeffress field is situated on a complex of five anastomosing growth faults. Frio strata show little deformation, forming a homocline with local noses. Only the deepest Frio beds are offset by faulting. Underlying Vicksburg strata are offset more than 1,200 ft across the faults at both fields.

In Flores field, reservoirs in the Vicksburg are largely localized on the flanks of rollover anticlines (fig. A-14). Offsets along the growth faults contribute to traps. The numerous faults and associated rollover anticlines at Jeffress field create the majority of traps.

Stratigraphic Framework and Sandstone Distribution

The Vicksburg section is more than 8,000 ft thick beneath Flores and Jeffress fields. Well logs of the Vicksburg show mainly thick, serrate, funnel-shaped (upward-coarsening) patterns typical of delta-front and distributary-channel sandstones. The uppermost Vicksburg contains two upward-fining packages. The lower Vicksburg sandstones have been interpreted as deposits of lobate, river-dominated deltas. The middle and upper Vicksburg sandstones have been interpreted as deposits of wave-dominated deltas.

Frio sandstones are found at depths of less than 4,700 ft at Flores field and 5,000 ft in Jeffress field. The Frio section is approximately 3,000 ft thick. Typical log patterns are blocky (massive) and bell-shaped (upward-fining) indicating a probable fluvial channel origin for the

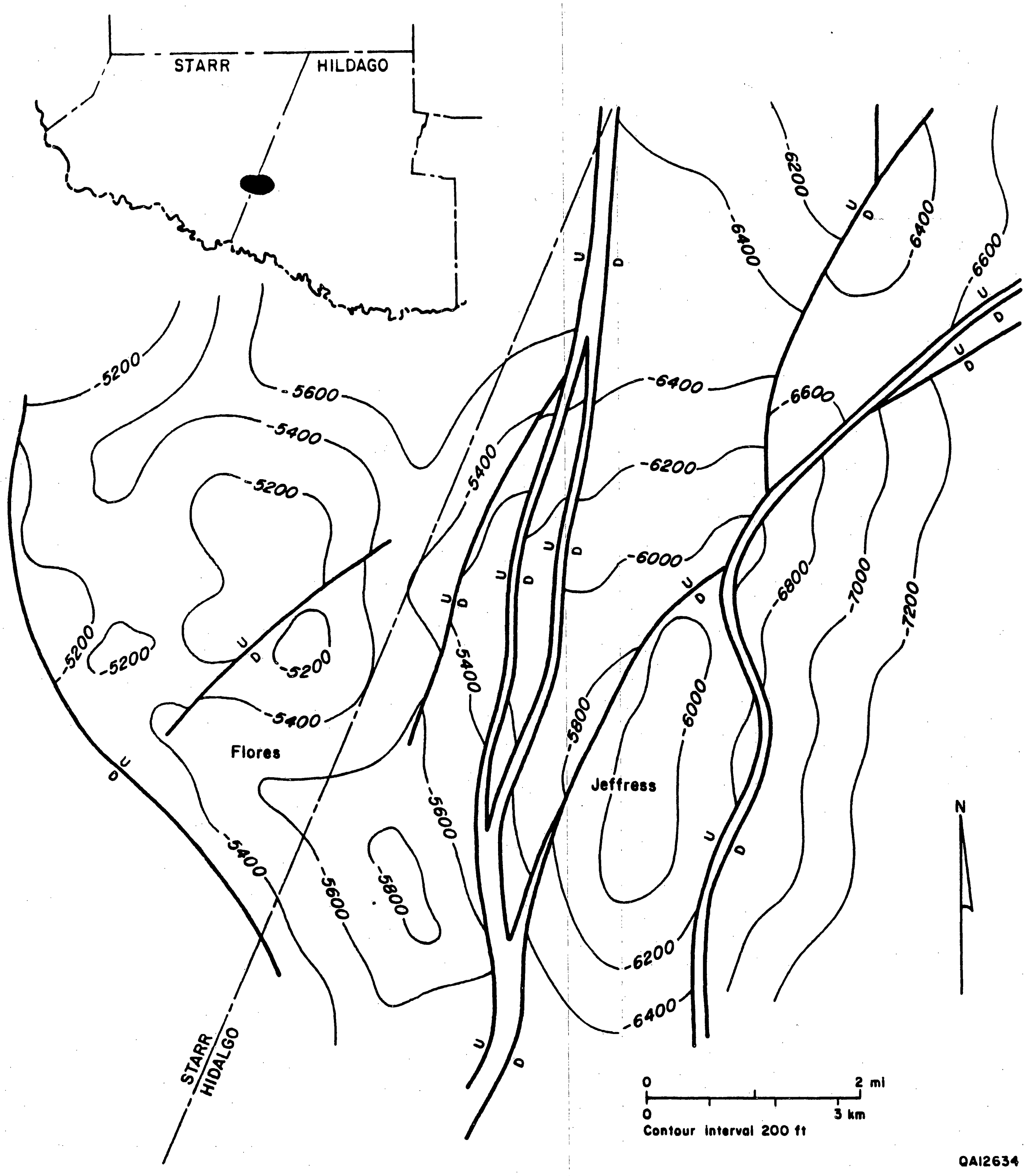

Figure A-14. Structure on top of the upper Vicksburg *Textularia warreni* zone, Flores and Jeffress fields, Starr and Hidalgo Counties. From Geomap.

sandstones. The Frio sandstones form a progradational package. These sandstones were probably deposited in wave- or river-dominated prograding delta systems.

Hydrocarbon Production

Flores and Jeffress fields are predominantly gas fields. Table A-12 presents data for reservoirs having more than 1 Bcf cumulative production and those discovered since 1980. Flores field produced more than 49 Bcf of gas between 1945 and 1987. Frio reservoirs produced 34 percent of the gas in this field. Sullivan Upper is the most important Frio reservoir, having produced about 15 Bcf, or 90 percent of the Frio and 30 percent of the fieldwide production (table A-12). Vicksburg reservoirs account for 66 percent of the production in the Flores field. Vicksburg lower is the most important Vicksburg reservoir, having produced more than 16 Bcf, or 50 percent of Vicksburg and 33 percent of the total Flores production (table A-12). Lower Frio reservoirs have been the main exploration and development targets in the last 5 yr. Drilling activity has largely been conducted by Sun Oil Company (now Oryx Energy Company). Jeffress field has produced more than 209 Bcf of gas since 1960, almost entirely from Vicksburg reservoirs. The only Frio reservoir is the Sullivan, which accounts for only 0.03 percent of the fieldwide production (table A-12). Vicksburg V is the most important Vicksburg reservoir in the field. It has produced approximately 88 Bcf or 42 percent of the fieldwide production (table A-12). Vicksburg reservoirs that lie between 7,000 ft and 12,000 ft beneath the surface have been the main exploration and development targets in the last 5 yr. The potential for reservoir compartmentalization within this interval is moderate to high, as expected in river-dominated delta systems.

Table A-12. Production data, Flores and Jeffress fields, Starr and Hidalgo Counties.

Reservoir name	Depth (ft)	Cum. prod. (MMcf)	Initial BHP/z	Year first produced	Status
		Flores Field			
Sullivan upper (Frio)	4,390	14,878	2,219	1951	SI 1985
Frio 4580	4,580	293	2,049	1985	
Frio 4485	4,485	94	2,163	1984	SI 1986
Hockley upper (Frio)	4,832	na	2,404	1982	
Vicksburg Lower	10,530	16,312	6,382	1974	
Vicksburg O	7,400	2,906	2,533	1971	
Rincon West (Vicksburg)	7,030	2,722	4,652	177	
Vicksburg 5600	5,600	2,359	2,730	1958	
Rincon (Vicksburg)	6,233	1,918	5,611	1949	
Vicksburg P West	8,195	1,578	5,286	1972	
Vicksburg 6300-R-1	6,340	1,190	4,053	1950	abd 1968
Rincon A (Vicksburg)	5,840	1,169	4,118	1970	
Rincon B (Vicksburg)	6,100	328	4,055	1982	
6200 Vicksburg	6,200	67	3,186	1986	
Vicksburg 5750	5,765	49	na	1986	
Vicksburg 6050	6,050	40	3,383	1982	abd 1985
Vicksburg 9300	8,980	33	na	1985	
First Rincon up str	6,640	8	na	1986	SI 1986
Vicksburg 5300	5,300	1	na	1984	abd 1986
		Jeffress Field			
Vicksburg V	11,980	87,887	7,125	1971	
Vicksburg W	1,369	68,528	6,976	1970	
Vicksburg U	11,500	42,436	7,147	1969	
Vicksburg S	8,680	5,858	6,044	1968	
Vicksburg T	10,266	2,497	6,202	1969	abd 1985
Vicksburg Q	8,180	1,081	5,782	1972	SI 1981
Vicksburg 7100	7,100	152	4,996	1985	
Vicksburg 6700	6,700	105	3,584	1980	
Vicksburg 7380	7,380	73	na	1981	abd 1985

na: not available; abd: abandoned; SI: shut-in

Recent Activity

Three wells were being drilled in Flores field and one in Jeffress field in early 1989. One well in Flores field was completed to 12,000 ft in the Vicksburg, with initial production of 268 MCFPD. The well being drilled in Jeffress field is also targeted at Vicksburg reservoirs.

Monte Christo Field, Hidalgo County

The Monte Christo field is located in the Rio Grande embayment (fig. 2), in west-central Hidalgo County, South Texas, approximately 18 mi north of Mission. It covers approximately 10 mi^2. The field was discovered in 1953 in the Superior Oil Company 1 Flora Johnson well, which bottomed at 11,052 ft. The well produced gas condensate at a CAOF potential of 26,500 MCFPD through casing perforations in the depth interval 6,340–6,350 ft (sand 27 of the Frio Formation). Gas production from the Vicksburg Formation was established later. During early field development, from 1953 to 1974, production from Frio and Vicksburg reservoirs was obtained in 18 wells.

Geologic Setting

Monte Christo is one of several gas fields in downthrown blocks of faults in the northeast-trending Vicksburg fault zone (fig. 2). Tabasco, South Monte Christo, North Monte Christo, and South Santellana are nearby fields related to the Vicksburg fault system. The field is stratigraphically and structurally similar to McAllen Ranch field, which is located approximately 10 mi to the north. Gas reservoirs of the Monte Christo field form part of the Oligocene Vicksburg VK-1 and lower Frio FR-4 plays.

Structural Framework

The field is a faulted rollover anticline in the downthrown block of the Monte Christo fault, which is a fault related to the Vicksburg fault system. The Vicksburg Formation at the crest of the anticline is shallowest at approximately 7,500 ft below sea level (fig. A-15). Sandstone beds thicken across the growth faults and are cut by synthetic and antithetic faults. Faulting in the Vicksburg Formation is more intense (more faults and larger throws) than in the Frio Formation.

Hydrocarbon Production and Field Characteristics

Cumulative gas production in the field, up to January 1987, was more than 236 Bcf from 61 Frio and Vicksburg reservoirs. Forty-eight of these reservoirs first produced in the 1980's. Table A-13 shows data for those reservoirs that have produced more than 10 Bcf of gas and those discovered since 1984. The Frio 27 sandstone and Vicksburg 57 sandstone have the highest cumulative productions. Initial potentials range from 180 MCFPD (in sandstone GG) and 280 MCFPD (in sandstone 58) to 32,422 MCFPD (in sandstone HH) and 53,000 MCFPD (in sandstone 26).

The large number of reservoirs result from stratigraphic heterogeneities and structural style. Producing intervals lie mostly at depths between 7,000 and 9,000 ft, but reservoir depths range from approximately 5,300 ft (Frio reservoirs) to more than 15,000 ft (Vicksburg reservoirs). Initial reservoir pressures range from about 12,000 psi in the Vicksburg 15300 sandstone and 10,900 psi in the Vicksburg PP sandstone to 2,020 psi in the 57-C sandstone.

Frio and Vicksburg sandstones have low porosity and permeability. Porosities range from 12 to 17 percent. Permeabilities usually are less than 1 md; therefore, well stimulation is locally essential for production. In the nearby Monte Christo South field, stimulation is normally not

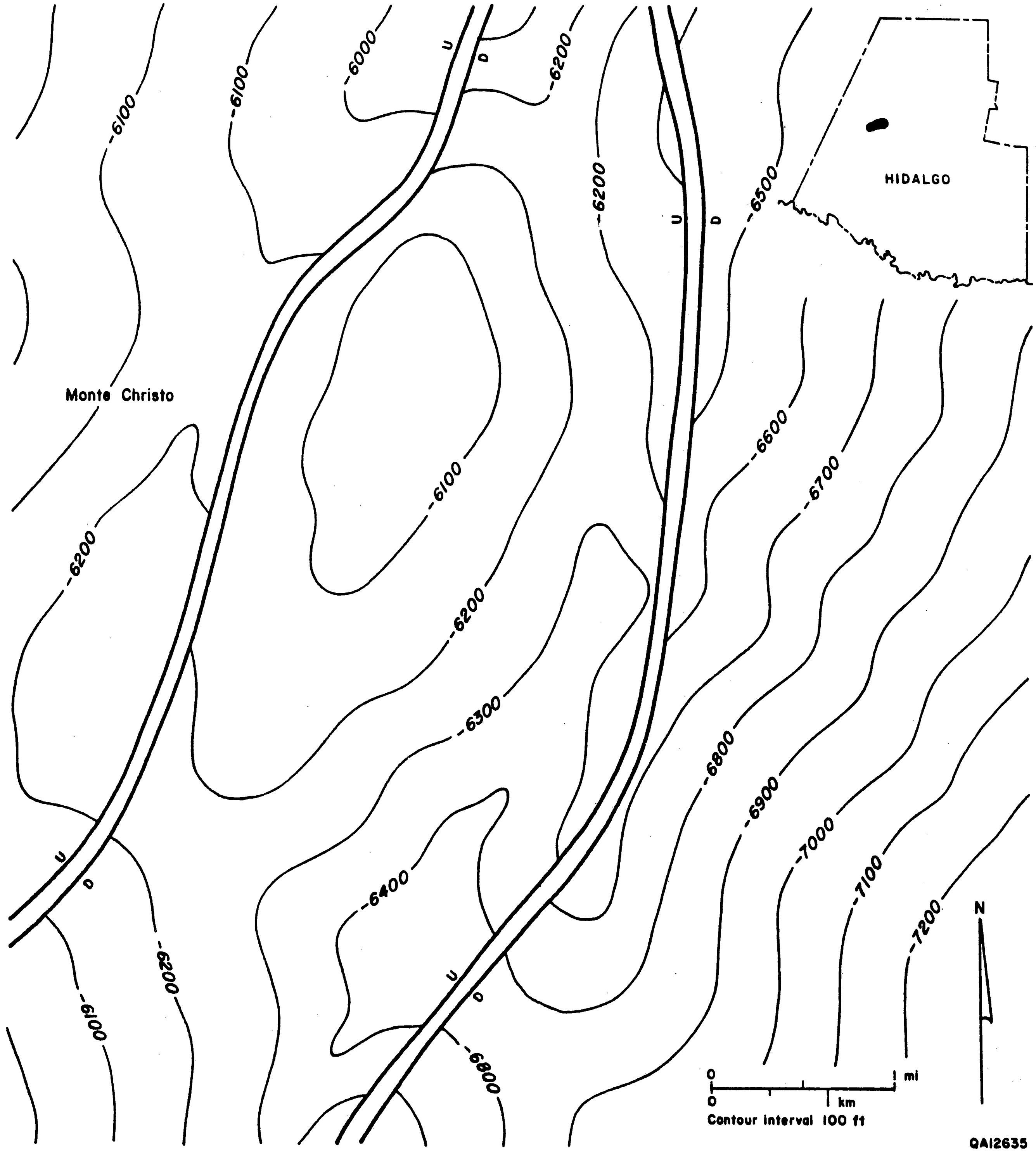

Figure A-15. Structure on top of a horizon in the lower Vicksburg, Monte Christo field, Hidalgo County. From Geomap.

Table A-13. Production data, Monte Christo field, Hidalgo County.

Reservoir name	Depth (ft)	Cum. prod. (MMcf)	Initial BHP/z	Year first produced
F-5 North	8,106	341	3,589	1984
F-5 South	8,238	759	4,567	1984
F-6	8,312	6,642	4,050	1984
F-6 SE	8,799	796	na	1985
F-4	7,722	560	3,438	1984
F-7	8,191	1,045	3,862	1984
F-8	8,139	257	3,868	1984
F-9	8,343	889	4,254	1984
F-10	8,250	442	4,002	1984
F-14-A	9,350	460	4,699	1984
F-16	9,502	642	4,730	1984
F-17	9,879	414	5,510	1984
Vicksburg Brown	14,522	857	na	1985
Vicksburg EE	9,562	340	6,132	1986
Vicksburg GG	11,061	8,393	5,305	1984
Vicksburg KK	13,204	19,249	8,031	1982
Vicksburg O-15	14,131	109	7,721	1984
25	6,215	20,933	3,086	1959
26	6,823	696	3,434	1984
27	5,310	62,339	3,155	1953
38-A	6,900	895	3,345	1984
38-B	6,936	48	na	1986
38-C	6,968	317	2,949	1984
39-A	7,056	1,216	4,238	1984
42	7,373	944	3,011	1984
46	7,608	1,080	3,717	1984
47	7,709	1,771	3,910	1984
48	7,781	763	4,503	1984
49	7,937	1,621	3,897	1984
50-A South	8,046	337	3,912	1984
50-B	7,922	14,630	4,363	1959
50-B South	8,173	3,753	5,046	1984
56-A	8,268	2,867	4,848	1984
56-A N	8,580	187	4,489	1986
56-B	8,441	3,212	4,742	1984
57	8,485	27,332	5,358	1959
57-B	8,692	2,338	5,059	1959
57-C	8,775	150	2,649	1984
58	8,825	1,804	4,481	1985
59	9,455	347	6,384	1985
9000	9,892	12,974	6,124	1961

na: not available; abd: abandoned

required for reservoirs above the F-14 sandstone, but acid and fracture treatments are necessary for reservoirs below this sandstone.

Recent Activities

Mobil Exploration and Producing U.S., Inc., drilled two wells in the Monte Christo field in 1988. One well had Frio reservoirs as its objective, whereas the Vicksburg was the objective in the other well.

The Mobil Johnson F-1 No. 58 well was spudded in April 1988 and bottomed at 8,908 ft. It was plugged back to 8,260 ft and completed in the Frio 52 and 56-B sandstones. The well is a new pool discovery that established gas production from the Frio 52 sandstone. Initial potentials were 1,745 MCFPD in the 52 sandstone and 5,200 MCFPD in the 56-B sandstone. Sidewall cores were taken in the well.

The Mobil Hamman John B No. 26 well was spudded in March 1988 and bottomed at 9,000 ft. It was sidetracked at 8,915 ft and plugged back to 8,340 ft. The initial Vicksburg objective is faulted out. The well tested 127 MCFPD and 1 BWPD on an 8/64-inch choke from the interval 8,297–8,332 ft. In addition, well tests indicated an estimated absolute open flow of 214 MCFPD in the 8,653–8,676 ft interval. Sidewall cores were taken in the well.

Yturria Field, Starr County

Yturria field covers approximately 10 mi^2 in east Starr County, near the Hidalgo County border, about 7 mi north of Sullivan City, in RRC district 4 (fig. 2). The field was discovered in 1941 when Sun Oil Company completed the Yturria No. 1 well in the Frio Formation. As of the end of 1987, 10 Frio and 7 Vicksburg reservoirs have been identified, and more than 80 wells have been drilled in the field.

Geologic Setting and Structural Framework

The field lies 4.5 mi east of the main Vicksburg fault in anticlinal structures on either side of a minor splay of the Vicksburg fault system. The Vicksburg growth fault was active primarily during deposition of the Vicksburg Formation, whereas the Frio Formation is little affected by Vicksburg faulting (fig. A-16), forming broad, subtle anticlines. Only the lower Frio beds are offset by faulting. Underlying Vicksburg strata show offsets of more than 1,000 ft and thicken considerably on the downthrown block. Gas in Vicksburg reservoirs is largely trapped in rollover anticlines associated with the faults.

Stratigraphic Framework and Sandstone Distribution

The Vicksburg section is more than 8,000 ft thick beneath Yturria field. Electric logs of the middle and upper Vicksburg are dominated by serrate, funnel-shaped (upward-coarsening) patterns typical of barrier-bar/strandplain and wave-dominated deltas. Lower Vicksburg sandstones have been interpreted as deposits of river-dominated deltas. These sandstones are more laterally discontinuous than sandstones of the middle and upper Vicksburg.

Frio sandstones in the field are found at less than 4,300 ft beneath the surface. Permeabilities are generally good, ranging from 0.1 to 1,000 md. Frio sandstones grossly form laterally extensive sheets; however, dip orientation of the channel bodies and internal permeability barriers result in small isolated reservoirs.

The Frio section in the field is approximately 3,000 ft thick. Well logs typically show blocky (massive) and bell-shaped (upward fining) log curves indicating a probable fluvial channel origin for the sandstones.

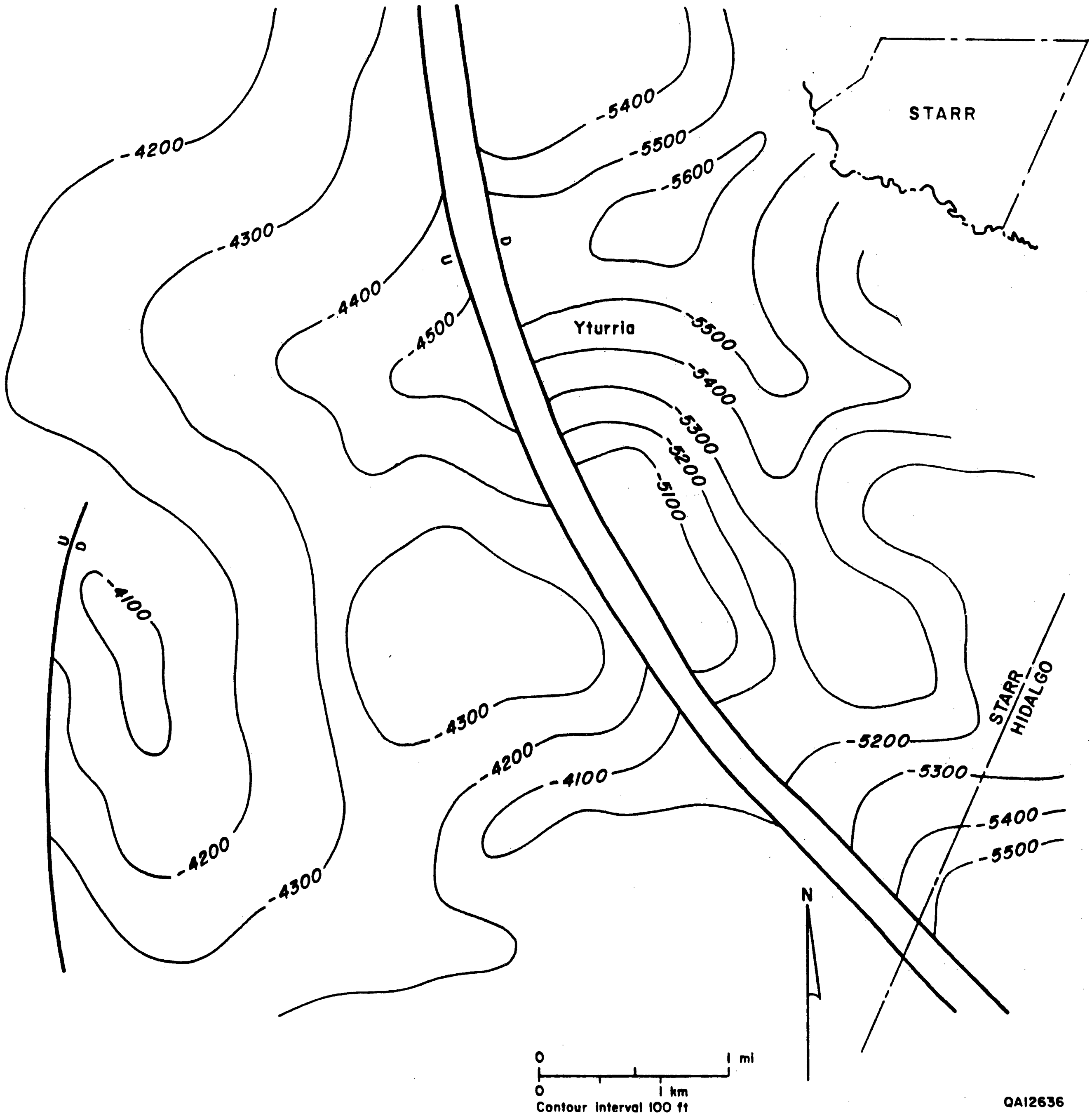

Figure A-16. Structure on top of the upper Vicksburg *Textularia warreni* zone, Yturria field, Starr County. From Geomap.

Hydrocarbon Production

As of the end of 1986, Yturria field had produced approximately 26 Bcf of gas (table A-14). Early production in the field was largely oil. Natural gas was reinjected during early development to enhance oil production, and therefore the gas production of some reservoirs may be overestimated due to unknown correction factors.

Frio reservoirs have produced 68 percent of the gas from the field. The 4100 reservoir, near the base of the Frio, is the most important, having produced 11.5 Bcf or 45 percent of the total.

Vicksburg reservoirs have been the main exploration and development targets for the last 10 years. Drilling activity was largely conducted by Sun Oil Company (now Oryx Energy Company). Main objectives have been deeper Vicksburg reservoirs and untapped lenticular sandstones within the Vicksburg. The numerous reservoirs that have been located at approximately the same stratigraphic intervals suggest reservoir compartmentalization within the upper Vicksburg and Frio.

Recent Activity

Sun Oil Company (now Oryx Energy Company) drilled two wells during the last quarter of 1988 and in early 1989. The targeted reservoirs are Vicksburg sandstones at depths ranging from 5,000 ft to 7,000 ft below sea level.

SUMMARY

This appendix contains results of initial screening of gas fields in the South-Central and South Texas coastal plain for suitability for the SGR project. Sandstone gas reservoirs in this

Table A-14. Production data, Yturria field, Starr County.

Reservoir name	Depth (ft)	Cum. prod. (MMcf)	Initial BHP/Z	Year first produced	Status
Frio 4100	4,157	11,558	2,269	1951	
Chapotal	4,200	2,531	1,474	1964	abd 1974
Frost A	3,965	1,078	na	1965	abd 1974
Frio 3700	3,690	1,034	1,820	1972	
Frio 3680	3,680	591	1,493	1974	
Frost B	4,232	528	na	1966	
Frio 4070	4,070	488	1,910	1971	abd 1984
Frio Stray 4230	4,230	432	1,904	1972	abd 1976
Vela	3,880	145	1,828	1974	abd 1985
Chapotal-C	4,220	92	1,278	1982	abd 1983
Vicksburg 4900	4,854	5,736	na	1964	
Vicksburg 4500	4,500	764	2,403	1962	abd 1976
Vicksburg 4920 Stray	4,920	278	na	1984	
Vicksburg 6,300	6,326	233	4,590	1962	abd 1964
Vicksburg 4,970 E	4,975	189	2,063	1974	abd 1982
Rincon 4660	4,662	113	2,158	1971	abd 1976
Vicksburg Yturria	5,153	38	3,503	1964	oil 1964

na: not available; abd: abandoned; oil: converted to oil field area were deposited during four major Tertiary depositional events: Wilcox, Vicksburg, Frio, and Miocene. Each depositional event was affected by relative sea-level changes, regional tectonic events, local subsidence variations, proximity to sediment input sources, and variations in atmospheric and oceanographic circulation patterns. The result is varying distribution of sandstone (reservoir) facies and mudstone (nonreservoir) facies both at the regional and local scales.

Data were compiled for 14 gas fields located in RRC districts 3 and 4. The structural setting and depositional systems of the gas-producing intervals were determined, a preliminary assessment was made of the potential for reservoir heterogeneity, and production history and recent operator activities were summarized for each field. Lake Creek, Lissie, and Sheridan fields are mainly Wilcox, Rockdale delta-system plays (Eocene). Lissie field is productive also from reservoirs in the Miocene Moulton/Pointblank streamplain system. Both depositional systems have good potential for reservoir compartmentalization. Lake Creek and Sheridan fields are anticlinal closures related to the Wilcox growth-fault zone. Lissie field, by contrast, is a complexly faulted anticlinal closure exhibiting strain patterns probably related to both growth faulting and salt tectonics.

The gas fields of RRC district 4 that were studied produce primarily from Oligocene Vicksburg and Frio reservoirs and to a lesser extent from Miocene reservoirs. Structural complexity in these fields generally increases with depth. Portilla, Rooke, and White Point East fields are part of Frio barrier/strandplain system plays and Miocene barrier/strandplain and fluvial systems plays. Structure of the Frio in Portilla and Rooke fields is relatively simple. In contrast, structure of the Frio in White Point East field is complex due to deformation along the Frio growth-fault system. Stratton, Agua Dulce, and Seeligson fields are part of Vicksburg and Frio deltaic and fluvial systems plays. The structure of Stratton field is a rollover anticline related to the Vicksburg growth-fault zone. McAllen Ranch field is part of a Vicksburg deltaic system play that comprises multiple-stacked, compartmentalized reservoirs. Low permeability, complex structure, and high reservoir pressure may affect an evaluation of reservoir heterogeneity. However, the field typifies reservoir conditions of a highly productive Gulf Coast Basin gas play in which exploration and development have lately been very intensive. Monte Christo, Flores, Jeffress, Lyda, and Yturria fields have multiple, stacked reservoirs that are part of Vicksburg and Frio deltaic and fluvial systems plays. Structural complexity varies from relatively simple folding in Flores field to faulted folding in Jeffress, Monte Christo, and Yturria fields.

Evaluated data indicate that Lake Creek, Stratton-Agua Dulce, Seeligson, and McAllen Ranch fields are good candidates for further studies in the SGR project. These fields have varying degrees of potential for untapped gas reserves and are good examples of a spectrum of geological and production characteristics of gas accumulations in the Texas coastal plain. Research activities during the first year therefore focused on these fields.

Appendix B.

Shale Porosity—Its Impact on Well Log Modeling and Interpretation

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SHALE POROSITY - ITS IMPACT ON WELL LOG MODELING AND INTERPRETATION

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ABSTRACT

Shale contains porosity which must be accounted for when evaluating well logs in shaly sands. Data is presented showing that in addition to relatively large amounts of total porosity (19-20%), shales may also contain significant effective porosity (8-12%).

When the effective porosity is greater than zero, shale can store hydrocarbons. As a result, actual in-place and recoverable hydrocarbons may be significantly higher than would normally be estimated when this effective porosity has not been accounted for. This problem may be particularly acute in a shaly sandstone gas reservoir.

An example is shown for core analysis data obtained from both sand and shale in a Frio formation gas reservoir in south Texas. Core data includes ambient porosity measured at 40% relative humidity and 140°F, and ambient total porosity measured at 230°F. Effective porosity is also presented utilizing the methods proposed by Hill, Shirley, and Klein[1]. A method of log analysis is then shown for modeling the total and effective porosity as obtained from core analysis. The result is a robust well log porosity interpretation model, which is in harmony with both the measured physical properties from the core analysis and the well log response.

INTRODUCTION

The industry has made significant progress in understanding and modeling shaly sandstone reservoirs for formation evaluation, but there are still some major problems. It is usually presumed that shale pore volume contains only immobile water, i.e., it cannot contain free hydrocarbons. As as result, many log computation models do not allow effective porosity in shale.

If no attempt is made to determine the effective porosity in the shales or very shaly intervals or to compute this effective porosity from log analysis, then hydrocarbon pore volume will be in error. If effective porosity does exist in a shale, it may be capable of storing hydrocarbons at a reasonable capillary pressure or height above the free water level.

DETERMINATION OF POROSITY

Shale may contain effective porosity in addition to significant amounts of total porosity. For the purpose of this paper, total porosity, $\varnothing_t$, is defined as the interconnected pore space occupied by water (both bound and free) and hydrocarbons. Effective porosity, $\varnothing_e$, is defined as the pore space occupied only by free water and hydrocarbons. It should be noted that this differs from the conventional definition of total and effective porosity when dealing with the reservoir rocks. Previously total porosity has been defined as the ratio of the total void space in the rock to the bulk volume of the rock and effective porosity as the ratio of the interconnected void space in the rock to the bulk volume of the rock, expressed in percent, regardless of the type of fluid in the void space.[2]

As part of a larger study, a conventional whole core was cut in a well in Seeligson Field, Jim Wells County, Texas. Thirty-six feet of whole core were recovered from 5,406' to 5,442'. Thirty-seven samples were selected for analysis. Two porosity measurements were made on each sample. A summary of these porosity measurements is presented in Table 1. The humidity dried ambient porosity was obtained by drying the samples at 40° relative humidity and 140°F. This reportedly will leave at least one to two layers of absorbed water on the clay surface.[3] The convection dried ambient porosities were determined by drying the samples at 230°F to constant weight.

In the sandstone interval, samples 1S through 14, there are small differences between the convection dried and humidity dried porosity with the humidity dried being slightly less. In the shale section, samples 15 through 28, large differences are noted between the humidity dried porosity and the convection dried porosity. The humidity dried porosity is approximately half the convection dried porosity.

These results are surprising on two accounts. First the convection dried porosity in the shale is quite large and not much less than the convection dried porosity in the sand for samples 2S through 6. For the shale the humidity dried porosity is much larger than expected. If the humidity dried porosity is in fact effective porosity as suggested by Bush[3], then the presumption that all shale pore volume contains only bound water may be erroneous.

STORAGE OF HYDROCARBONS

According to Hill, Klein, and Shirley[1] (HSK), if a rock contains effective porosity, whether it occurs in sand or shale, the rock will be capable of storing hydrocarbons. Suppose a rock containing some bound water is first cleaned and dried at convection oven drying conditions so as to remove all bound water. When mercury is injected into the rock sample at some pressure, the volume of pore space occupied by mercury will be larger than the volume of gas which would be contained in this same void volume segment if gas were introduced into the brine saturated rock in a capillary pressure cell (restored state or centrifuge) to an equivalent height above free water level. According to Hill et al, if the distribution of clay and therefore bound water is assumed to be such that any particular void volume segment contains its proportional amount of bound water, then mercury saturation, S_{Hg}, is given by

$$S_{Hg} = S_g + S_{Hg} V_b / V_t \quad \cdots\cdots (1)$$

or

$$S_g = S_{Hg}\left(1 - V_b / V_t\right) = S_{Hg}\frac{\varnothing_e}{\varnothing_t} \quad \cdots\cdots (2)$$

S_g - gas saturation from gas-brine capillary pressure test
S_{Hg} - mercury saturation from mercury capillary pressure test
V_b - bulk volume bound water
V_t - bulk volume bound water + bulk volume pore water
$\varnothing_t$ - total porosity
$\varnothing_e$ - effective porosity

From Equation 2 we can see that any rock with effective porosity greater than zero can store hydrocarbon, at least at some capillary pressure level.

Three samples were selected for determination of air-brine capillary pressure curves. Two of the samples were sandstone and one sample was shale. In addition, mercury injection capillary pressure curves were determined on these same three samples plus an additional two shale samples. All measurements were converted to equivalent height above the free water level in the gas reservoir.

air-brine

$$H = 1.435\ P_c \qquad (3)$$

air-mercury

$$H = 0.281\ P_c \qquad (4)$$

H - height above free water level, ft

P_c - capillary pressure, psi

The relationship for one of the sandstone samples is shown in Figure 1. The relationship for the shale sample is shown in Figure 2. Effective porosity from the air-brine and air-mercury capillary pressure data may be estimated from Equation 2.

$$\varnothing_e = \varnothing_t \frac{S_g}{S_{Hg}} \qquad (5)$$

This provides another means of estimating the effective porosity in addition to using the humidity dried porosity. The comparison of humidity dried porosity and the porosity derived from the capillary pressure is shown in Table 2. The effective porosity derived from the capillary pressure data is generally lower than the humidity dried porosity for the three samples analyzed. The shale sample (sample #18) shows an effective porosity of 8.1% from the capillary pressure data. This effective porosity in the shale can store hydrocarbons.

The volume of mercury and the volume of air at an equivalent height of 570 feet above the free water level was computed from the mercury and brine saturations as follows:

$$V_{Hg} = \varnothing_t S_{Hg} \qquad (6)$$

$$V_g = \varnothing_t (1 - S_w) \qquad (7)$$

The results indicate that an equivalent shale associated with a sandstone reservoir would contain roughly 14% of the gas a sandstone of equal thickness would hold.

Mercury injection curves were run on an additional two shale samples. The volume of mercury injected at the maximum pressure decreases significantly as the humidity dried porosity decreases for both the sand and shale samples. For the convection dried porosity there is practically no relationship to mercury volume injected. Additional air-brine capillary pressures were not run on the shale samples in this well because of the lack of suitable core on which to take plugs. It should be noted that on all samples below sample

#19, the porosity analysis was performed on shale pieces selected from the conventional core.

EFFECTIVE POROSITY FROM CATION EXCHANGE CAPACITY

Calculations of effective porosity utilizing cation exchange capacity (CEC) data yield results that are less than the humidity dried porosity for all of the samples analyzed. The CEC effective porosity is almost equal to the Pc derived effective porosity for the two sandstone samples. However, for all of the shale samples, the CEC data yield unreasonable negative porosities.

The relationship for determining effective porosity from CEC is given by the following Equation[1]

$$\varnothing_e = \varnothing_t \left[1 - \left(0.084\, C_o^{-1/2} + .22 \right) \frac{Q_v}{\rho_{CBW}} \right] \qquad (8)$$

where

$$Q_v = \frac{CEC(1 - \varnothing_t)\,\rho_g}{100\,\varnothing_t}$$

$\varnothing_t$	- convection dried porosity
C_o	- salinity in meq/cm^3
Q_v	- quantity of cation exchangeable clay present in meq/cm^3 of pore space
ρ_{CBW}	- density of clay bound water in meq/100 gm - assumed to be 1.00.
CEC	- cation exchange capacity in meq/100 gm
ρ_g	- convection dried grain density

Table 3 summarizes the core data and the resulting computation of effective porosity from CEC. The results for effective porosity appear reasonable in all the sandstones (down to and including sample #14). When the shales are analyzed, the computed effective porosities become negative.

The CEC was measured by pulverising the samples to pass a 60 mesh sieve. Previously published work[4,5] has shown that the wet chemistry method gives reasonable values of CEC at low values of CEC. However, due to possible "broken bonds", grinding finer increases the cation exchange capacity of the sample. On the other hand, Equation 8 was developed by Hill et al on disaggregated samples. As a result, it would be expected that their relationship for the clay bound water would be applicable for disaggregated samples. This is obviously not the case.

As a cross check, the weights of the humidity dried samples and convection dried samples were utilized to compute the absorbed water index[6] and from this to obtain a value of CEC. On the average, the CEC values derived from the absorbed water index were 24% higher than those CEC values measured in the shales using the wet chemistry method. The utilization of the CEC determined from the absorbed water index would result in greater negative effective porosities than those computed from the CEC determined by wet chemistry. Several possibilities exist. The use of the absorbed water index in order to determine CEC may not be applicable for shale formations. It is possible that CEC determined by wet chemistry using pulverized samples may not be used with Equation 8 to determine effective porosities in shale. It is also possible that the correlation developed by Hill et al may not be applicable in shale formations.

Measurements using membrane potential may be the only reasonable method for obtaining CEC in shale formations. However, at the present time, this service is not commercially available on a routine basis. The only commercially available method of determining effective porosity is through use of the capillary pressure data. Although the humidity dried porosity yields higher values for effective porosity than the Hill et al capillary pressure method the results are in qualitative agreement. The humidity dried porosity method might yield values in better agreement if the drying was done at a lower temperature or a higher relative humidity. Much more data are needed to pursue this application of the humidity dried porosity.

It may also be possible to calibrate or normalize the humidity dried porosity to the effective porosity determined from capillary pressure data in the shales.

APPLICATIONS FOR LOG ANALYSIS

The well logs recorded on this Seeligson Field well included the dual induction, density, neutron, gamma ray and acoustic log. These logs are shown over the cored interval in Figure 3. The conventional core was obtain from the 15 sand and from the adjacent shale below this sand. The core depths were shifted up 7.5 feet to match the well log depths.

The primary mineral constituents of the rock are quartz, plagioclase, K-feldspar, calcite and smectite clay. Table 4 summarizes the volume percentages. The clays were originally reported in weight percent but were converted to volume percent using the following relationship

$$V\% = \frac{WT\%\ \rho_c}{\rho_g} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (9)$$

ρ_c - convection oven dried grain density of the composite rock

ρ_g - grain density of the mineral

Data was available for mineral content from both infrared absorption and x-ray diffraction.

The well log clay indicators were calibrated to the clay content determined from the infrared absorption using previously published techniques.[7] The clay indicators utilized were the density-neutron, neutron-sonic, neutron, and SP. The minimum clay indicator from these multiple indicators was selected to determine the clay content. Figure 4 compares the core derived clay volume to the well log derived clay volume.

Porosity may be determined from the density or the neutron log corrected for clay content utilizing the two following general relationships

$$\emptyset = \frac{\rho_g - \rho_b}{\rho_g - \rho_f} - \frac{\rho_g - \rho_{cl}}{\rho_g - \rho_f} V_{cl} \quad \text{.........................} \quad (10)$$

$$\emptyset = \frac{\emptyset_n}{\emptyset_{nf}} - \frac{\emptyset_{ncl}}{\emptyset_{nf}} V_{cl} \quad \text{..............................} \quad (11)$$

V_{cl} - bulk volume clay
$\emptyset$ - porosity, either total or effective
ρ_g - grain density
ρ_f - fluid density
ρ_{cl} - clay density
$\emptyset_{nf}$ - neutron fluid
$\emptyset_{ncl}$ - neutron clay

If the porosity of interest is total porosity, then the values for clay density and neutron clay would be the dry values. If the porosity to be solved for is the effective porosity, then the values for clay density and neutron clay response would be the wet clay values. It should be noted here that the dry clay density is generally in the range of 2.65 g/cc. As a result the density log (in sandstone porosity units) yields a good estimate of total porosity. This is because dry clay grain density is equal to the grain density of quartz and the density porosity was recorded on a 2.65 g/cc matrix. The above relationships can also be used to solve for the appropriate clay parameters when values of effective porosity and total porosity are available from core analysis. Rearranging Equations 10 and 11 we have

$$\rho_{cl} = \frac{V_{cl}\rho_g - \left(\frac{\rho_g - \rho_b}{\rho_g - \rho_f} - \emptyset\right)(\rho_g - \rho_f)}{V_{cl}} \quad \text{..................} \quad (12)$$

$$\emptyset_{ncl} = \frac{\left(\frac{\emptyset_n}{\emptyset_{nf}} - \emptyset\right)\emptyset_{nf}}{V_{cl}} \quad \text{..............................} \quad (13)$$

When the property of dry clay is to be determined, the value of total porosity from convection dried core analysis is used within the shale interval. When the value for wet clay is to be determined, the value for effective porosity is utilized within the shale interval. To demonstrate the application, in this example the humidity dried porosity is utilized for effective porosity. Although it may be a little high it serves the purpose of demonstrating the application. A value of 2.66 g/cc was computed for the density of dry clay and a value of 2.21 g/cc was computed for the wet clay density values. Interestingly enough, these are not very much different from the published values of 2.63 g/cc and 2.26 g/cc for montmorillorite and montmorillorite with $4H_2O$.[8] The values for neutron dry clay and neutron wet clay were 0.53 and 0.79 respectively. These do not correspond to the published values for neutron clay response of between 0.126 and 0.115 for dry clay and between 0.519 and 0.500 for wet clay.

These parameters were then utilized in Equations 10 and 11 to determine the total porosity and effective porosity for all the cored depth interval from the density and neutron logs. When the neutron log was less than the density log after correcting for clay content, it was assumed to be due to the influence of gas and the following general relationship was utilized to determine the final porosity.

$$\varnothing = \frac{A\varnothing_d + B\varnothing_n}{A + B} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (14)$$

where A and B are constants which determine the slope of the gas correction line back to the correct porosity value. This allows for a solution of both effective porosity and total porosity without calculating water saturation in order to determine a light hydrocarbon correction.

Figure 5 compares the computed total porosity from the density and neutron logs with the convection dried core porosity. As noted previously, the total porosity in the shale is not much different than the porosity in the sand. Figure 6 compares the humidity dried core porosity with effective porosity computed from the density and neutron. In both cases the fit between core derived porosity and log derived porosity is very good.

A single porosity device can be utilized to determine both total and effective porosity. However, if light hydrocarbons are present the porosities must be corrected for the presence of these light hydrocarbons. This necessitates the calculation of a log derived water saturation before a final porosity value can be derived.

The density lends itself to the determination of effective and total porosity using a single porosity device. The dry clay density is generally very close to the density of quartz, thus total porosity is read directly with little or no correction. The correction to obtain effective porosity from the density, although significant, is less than the correction that would be required to obtain effective porosity from the neutron log or acoustic log.

Total porosity and effective porosity were computed from the density log only using the following relationships to correct for residual hydrocarbons in this gas well. A reiterative solution was utilized as total porosity changed as a function of water saturation. Since bulk volume hydrocarbons must be equal in the total and effective porosity system effective water saturation was determined using total water saturation and total and effective porosity.

$$S_{wt}^{\,n} = \frac{R_w}{\varnothing_t^{\,m} R_{ild}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (15)$$

$$S_{xo} = S_{wt}^{\,0.2} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (16)$$

$$\Delta\varnothing_{hy} = \left(\frac{\rho_g - \rho_{hy}}{\rho_g - \rho_f}\right) \varnothing_t (1 - S_{xo}) \qquad (17)$$

$$S_{we} = 1 - \frac{\varnothing_t}{\varnothing_e}(1 - S_{wt})$$

$\Delta\varnothing_{hy}$ - correction for hydrocarbon
ρ_{hy} - apparent density of the hydrocarbon

The computed results for total porosity and effective porosity from the density log alone is compared to core analysis in Figures 7 and 8 respectively. The results are of similar good quality as that obtained using both the neutron and the density.

A log presentation of the computed results for the density-neutron combination and the density only combination is presented in Figure 9 along with the respective core analyses. All parameters utilized in these log computations are summarized in Table 5.

DISCUSSION

The data presented in this paper shows that effective porosity can exist in shales and store hydrocarbon. Although effective porosity may be difficult to determine from core analysis, every attempt should be made to determine its magnitude and impact on reservoir volumetrics.

The occurrence of effective porosity in shales will have the largest impact in gas reservoirs without an active water drive. Gas stored in effective shale porosity could contribute to production as the reservoir is depleted and the pressure differential between the shale and sand beds increases, causing the migration of gas from the shales into the sands where it may be produced. Effective porosity in the shales may also become evident when a partially depleted reservoir with no active water drive is shut in or production significantly curtailed. This evidence may exhibit itself through an increasing reservoir pressure as the field remains shut in. This could be due to the flow of gas or free water associated with the effective porosity in the shales to the higher permeability sand reservoir, thus increasing overall reservoir pressure.

In this paper no attempt has been made to address the proper determination of water saturation. It is clear that the correct determination of total porosity and effective porosity in shales and shaly sands is necessary if there is to be any adequate determination of water saturation or reservoir volumetrics from well logs.

CONCLUSIONS

1. Shale can contain significant amounts of effective porosity in addition to large amounts of total porosity.

2. This effective porosity can store hydrocarbons.

3. There is a need for a routine, commercially available method of determining effective porosity on cores.

4. There is a need for commercially available membrane potential measurements for the determination of cation exchange capacity.

5. The method developed by Hill et al[1] for effective porosity determination utilizing cation exchange capacity does not appear to apply in shale. Although the reason for this is not clear at this time, it may be due to using pulversized shale samples.

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TABLE 1
HUMIDITY DRIED AND CONVECTION DRIED
CORE POROSITY RESULTS
SHALE SAMPLES BEGIN WITH SAMPLE NO.15

SAMPLE NUMBER	DEPTH	HUMIDITY DRIED POROSITY	CONVECTION DRIED POROSITY
1S	5406.3	21.7	22.0
1	5406.4	20.9	21.3
2S	5407.3	20.5	20.8
3S	5408.2	19.5	19.9
4S	5409.1	20.5	20.8
2	5410.1	23.0	23.5
3	5411.1	20.1	20.7
4	5412.1	20.6	20.6
5S	5413.4	20.4	20.5
5	5414.2	21.3	21.7
6S	5415.7	21.6	22.1
6	5416.3	18.3	20.4
7S	5417.2	26.5	26.7
7	5418.2	27.5	27.7
8S	5419.3	22.9	23.3
8	5420.2	26.6	26.8
9S	5421.3	23.9	24.2
9	5422.1	25.6	25.7
10	5423.1	24.8	24.9
11	5424.3	21.4	22.4
12	5425.6	19.8	21.2
13	5426.1	19.4	20.3
14	5427.4	21.5	22.5
15	5428.6	11.6	19.5
16	5429.8	11.2	19.4
17	5430.2	9.3	15.5
18	5431.5	12.2	19.8
19	5432.2	11.6	19.6
20	5433.1	10.9	19.8
21	5434.0	9.9	20.7
22	5435.0	7.8	19.3
23	5436.0	8.9	19.9
24	5437.0	9.0	19.4
25	5438.0	8.8	17.9
26	5439.0	9.0	18.0
27	5440.0	9.1	17.9
28	5441.0	8.2	15.8

TABLE 2
COMPARISON OF HUMIDITY DRIED POROSITY WITH EFFECTIVE
POROSITY FROM CAPILLARY PRESSURE INCLUDING THE
RESULTING BULK VOLUME MERCURY AND AIR

SAMPLE NUMBER	DEPTH	CONVECTION DRIED POROSITY	HUMIDITY DRIED POROSITY	P_c EFFECTIVE POROSITY HSK	V_{Hg} @ 570'	V_g @ 570'
2	5410.0	23.5	23.0	22.3	0.208	0.198
6S	5415.7	22.1	21.6	21.9	0.181	0.179
18	5431.5	19.8	12.2	8.1	0.066	0.027
20	5433.1	19.8	10.9	- -	0.057	- -
24	5437.0	19.4	9.0	- -	0.016	- -

TABLE 3

COMPARISON OF EFFECTIVE POROSITY COMPUTED FROM CEC AND HUMIDITY DRIED CORE POROSITY

SAMPLE NUMBER	DEPTH	CONVECTION DRIED POROSITY	CONVECTION DRIED GRAIN DENSITY	CEC	Q_v	CEC EFFECTIVE POROSITY HSK	HUMIDITY DRIED POROSITY
1	5406.4	21.3	2.68	2.55	0.25	19.4	20.9
3S	5408.2	19.9	2.68	1.76	0.19	18.6	19.5
2	5410.1	23.5	2.68	2.84	0.25	21.3	23.0
4	5412.1	20.6	2.68	2.88	0.30	18.5	20.6
5	5414.2	21.7	2.68	2.91	0.28	19.6	21.3
6S	5415.7	22.1	2.67	2.06	0.19	20.6	21.6
6	5416.3	20.4	2.69	2.06	0.22	18.9	18.3
7S	5417.2	26.7	2.66	2.06	0.15	25.3	26.5
8S	5419.3	23.3	2.67	1.41	0.12	22.3	22.9
9S	5421.3	24.2	2.66	3.47	0.29	21.8	23.9
10	5423.1	24.9	2.66	2.60	0.21	23.1	24.8
12	5425.6	21.2	2.67	5.61	0.56	17.1	19.8
14	5427.4	22.5	2.66	3.78	0.35	19.8	21.5
16	5429.8	19.4	2.68	37.27	4.15	-8.4	11.2
18	5431.5	19.8	2.66	44.20	4.76	-12.7	12.2
20	5433.1	19.8	2.66	37.76	4.07	-8.0	10.9
22	5435.0	19.3	2.63	45.41	4.99	-14.0	7.8
24	5437.0	19.4	2.64	42.69	4.68	-11.9	9.0
26	5439.0	18.0	2.64	33.94	4.08	-7.3	9.0
28	5441.0	15.8	2.63	33.59	4.71	-9.9	8.2

TABLE 4

SUMMARY OF AVERAGE MINERAL PERCENTAGES FOR THE SANDSTONE AND SHALE INTERVALS

MINERAL VOL %	SAND	SHALE
QUARTZ	37	25
PLAGIOCLASE	23	5
k-FELDSPAR	11	20
CALCITE	20	12
DOLOMITE	1	0
CLAY	8	38

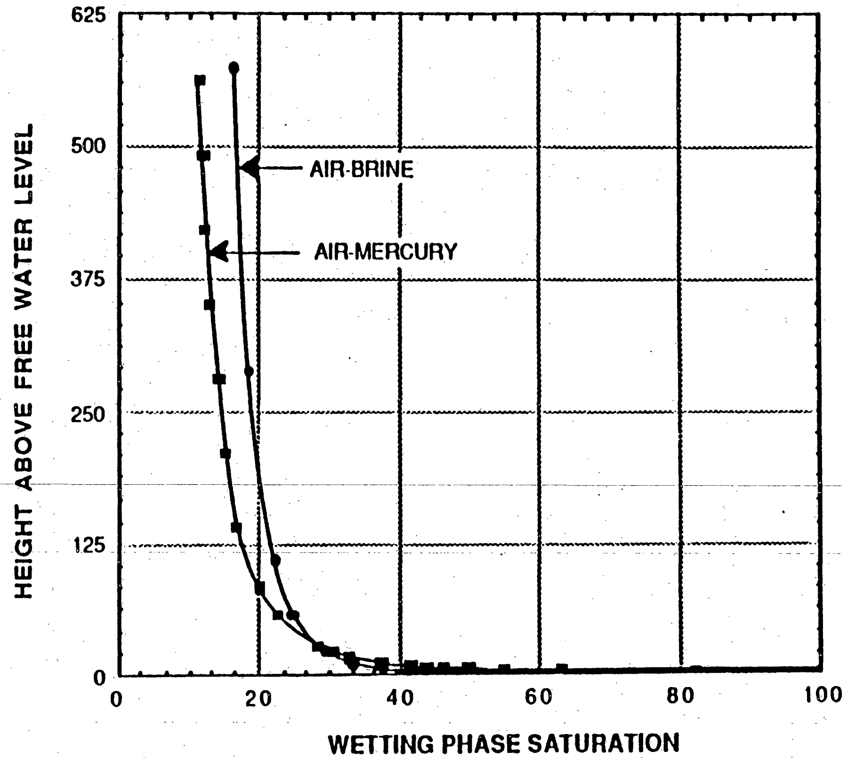

Figure 1. Comparison of capillary pressure data for air-brine and air-mercury for one of the sandstone samples. (sample No. 2)

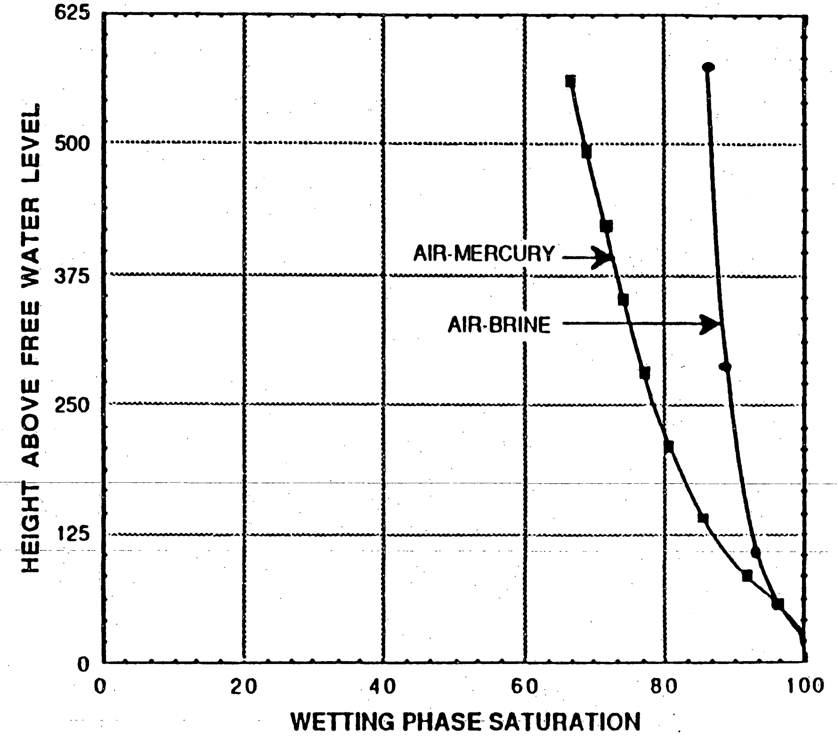

Figure 2. Comparison of capillary pressure data for air-brine and air-mercury for the shale sample. (sample No. 18)

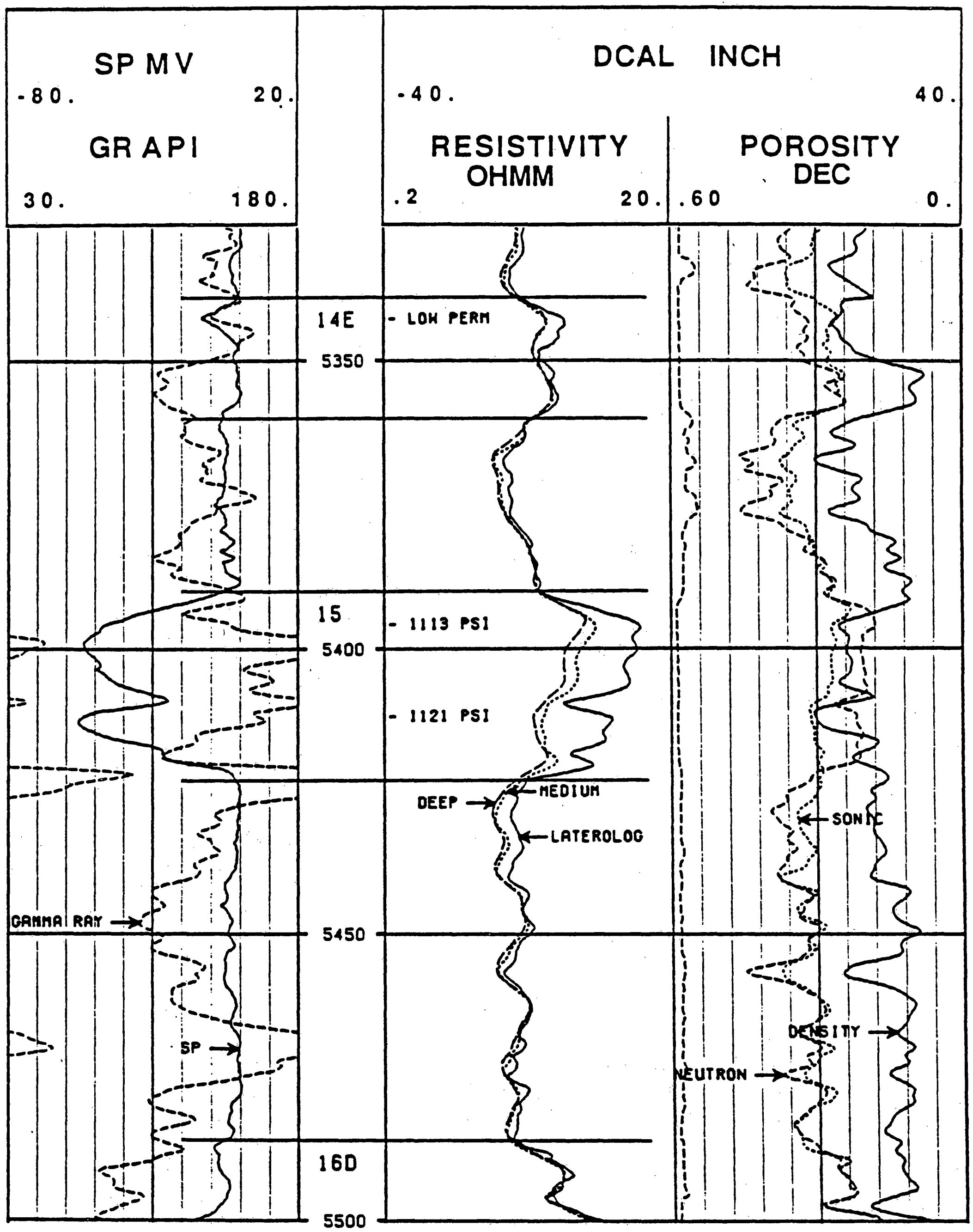

Figure 3. Open hole logs after editing. Conventional core was taken from 5398'-5434' log depth.

TABLE 5

PARAMETERS UTILIZED FOR COMPUTATION
OF THE WELL LOGS

$\rho_g = 2.67$	$\varnothing_{nm} = 0$
$\rho_f = 0.97^9$	$\varnothing_{nf} = 0.97$
$\rho_{clwet} = 2.21$	$\varnothing_{nclwet} = 0.79$
$\rho_{cldry} = 2.66$	$\varnothing_{ncldry} = 0.53$
$\rho_{gas} = -.12^9$	----
A = 9	B = 2
m = 1.89	n = 1.79
R_w = 0.11 @ 162°F	
Reservoir Pressure = 1120 psi	

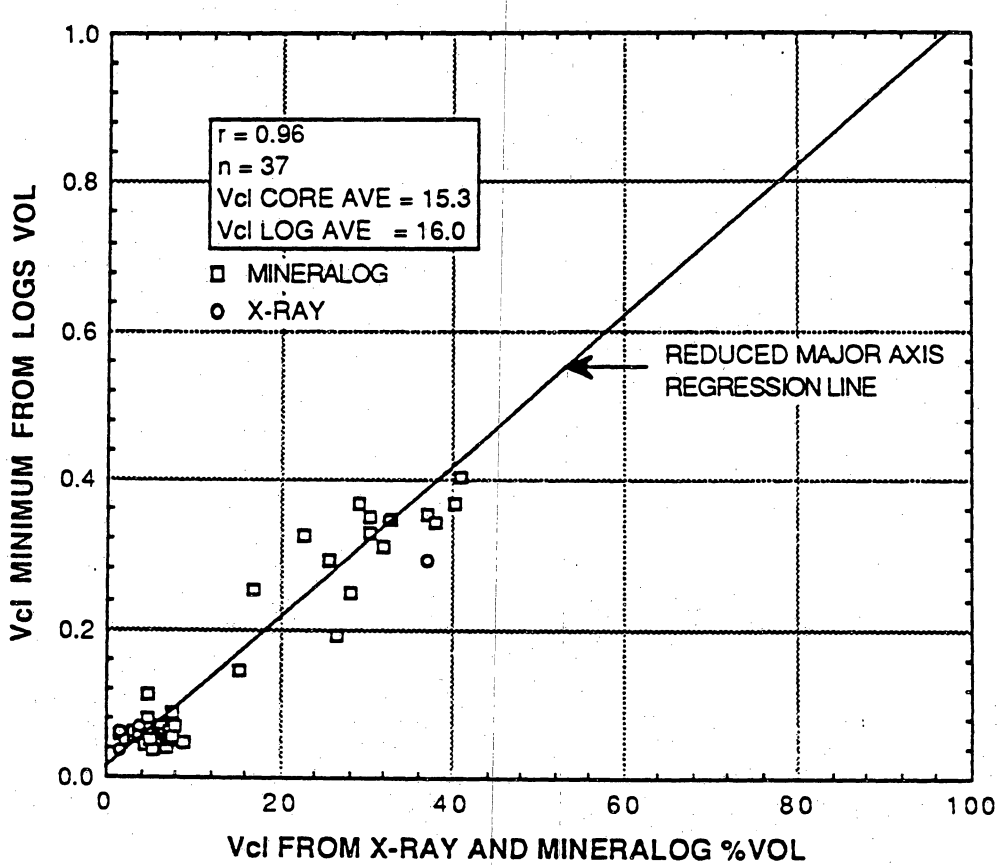

Figure 4. Comparison of clay volume from core analysis and clay volume determined from well logs.

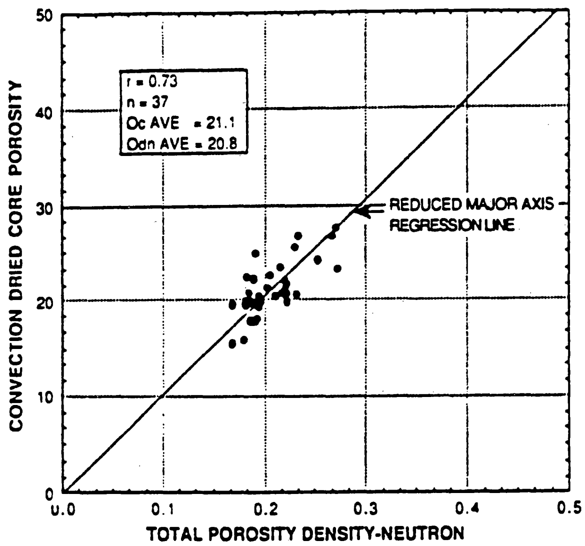

Figure 5. Comparison of convection dried core porosity with total computed porosity from the density and neutron logs.

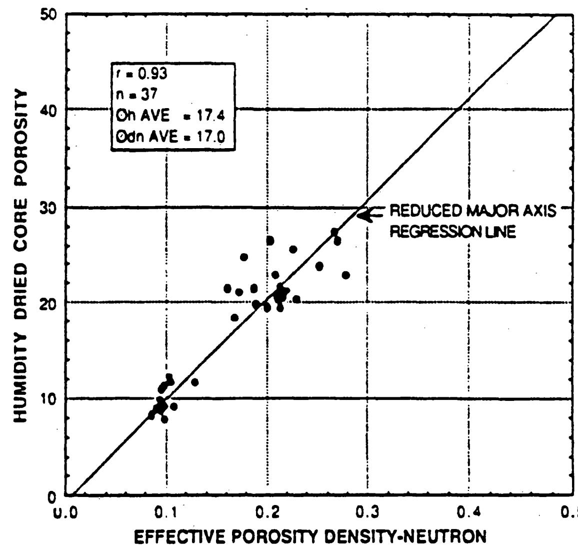

Figure 6. Comparison of humidity dried core porosity with effective porosity computed from the density and neutron logs.

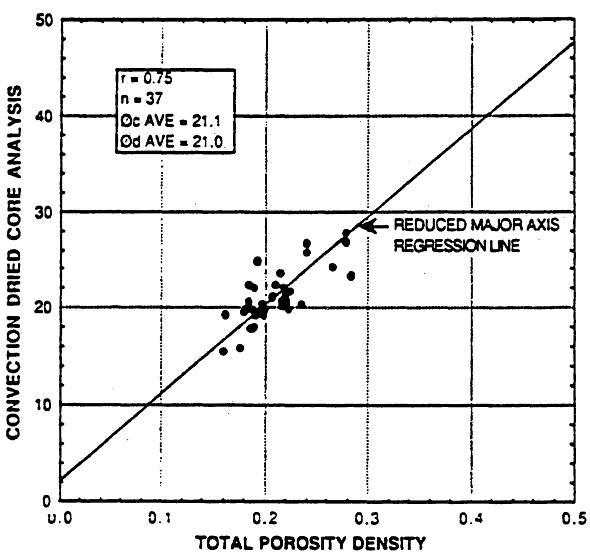

Figure 7. Comparison of convection dried core porosity with total computed porosity from the density log.

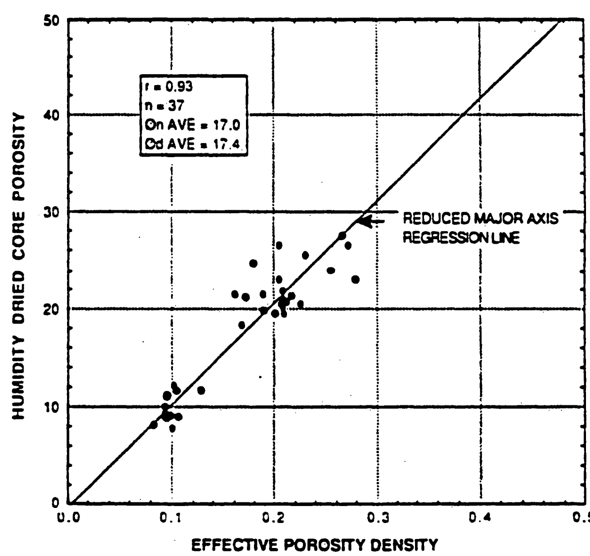

Figure 8. Comparison of humidity dried core porosity with effective porosity computed from the density log.

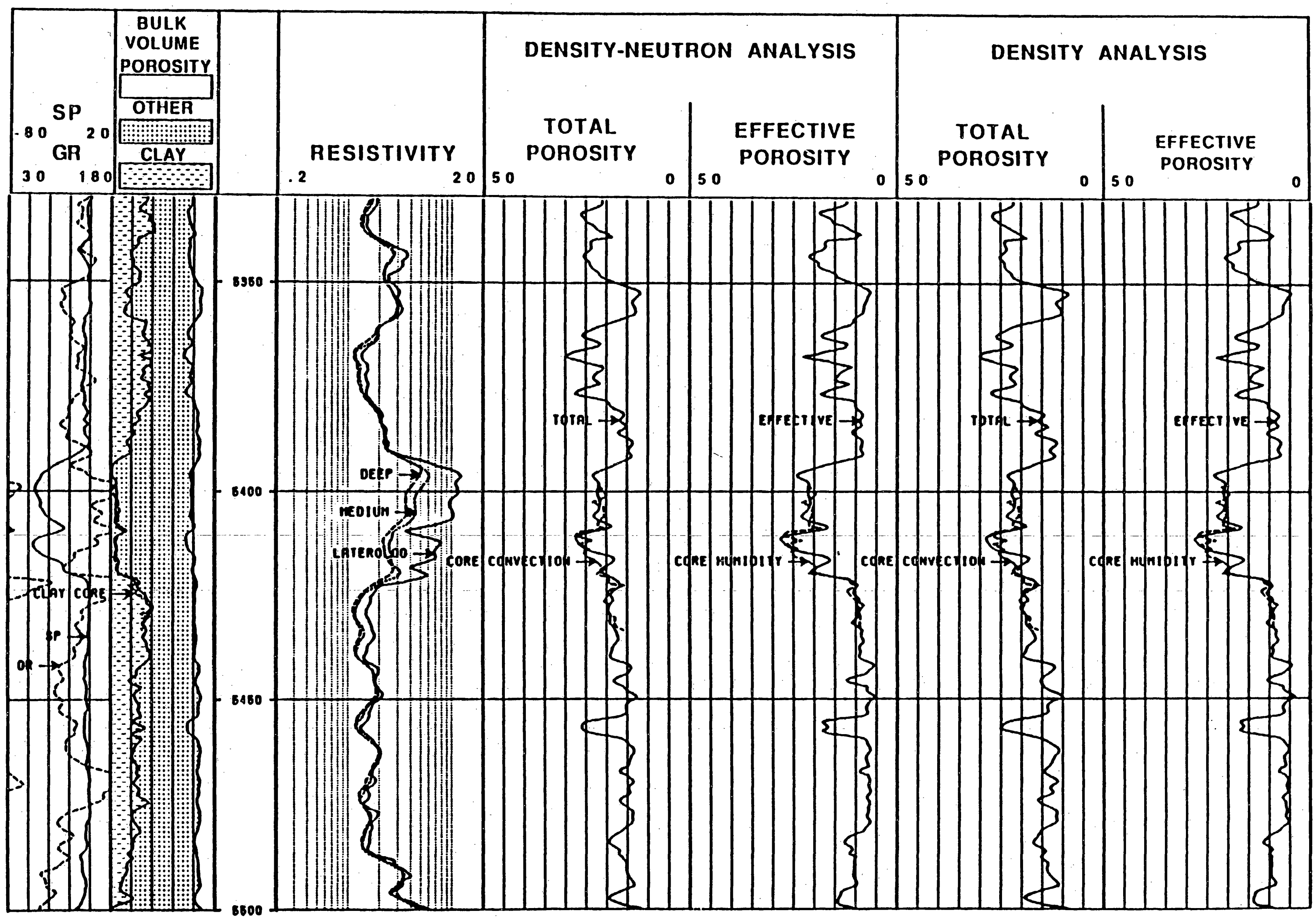

Figure 9. Comparison of computations for clay volume, total and effective porosity versus core analysis, convection and humidity dried porosity.