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EXTRAPOLATION OF GAS RESERVE GROWTH POTENTIAL: DEVELOPMENT OF EXAMPLES FROM MACRO APPROACHES

FINAL REPORT

(October 1990–November 1991)

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16. Abstract (Limit: 200 words)

An analysis of infield completions and reserve growth potential was made in Tertiary nonassociated gas reservoirs in South Texas. Infield well completions were defined from a concurrent GRI project involving macro-scale prediction of reserve growth. This report validates 78 percent, or 5.6 Tcf, of a high-end infill estimate of 7.2 Tcf for nine stratigraphic units in South Texas. This is a significant resource volume given the historical expectation that natural gas can be efficiently drained with widely spaced wells (1 or 2 per square mile) in conventional reservoirs.

Groups of infield completions, or reservoir sections, from Frio, Vicksburg, Wilcox, and Miocene reservoirs were examined using geophysical well logs and production and pressure analyses. Seven reservoir-section types that contributed to the macro reserve growth estimate were evaluated. About 20 percent of the estimate consists of gas volumes extrapolated using consolidated reservoir groups, cycled reservoirs, and reservoirs with invalid data. Additional gas volumes in the estimate were extrapolated from reservoir sections representing rate acceleration. The estimate also includes reservoir volumes from the low-permeability Wilcox Lobo trend, where limited drainage radii lead to expected reserve growth. Volumes that represent within-reservoir reserve growth and volumes that represent shallower- or deeper-pool reservoirs determined not to be in pressure communication with preceding completions in a reservoir section formed most of the macro reserve growth estimate.

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RESEARCH SUMMARY

Title	Extrapolation of Gas Reserve Growth Potential: Development of Examples from Macro Approaches
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5090-212-2076, entitled "Extrapolation of Gas Reserve Growth Potential: Development of Examples from Macro Approaches."
Principal Investigator	R. J. Finley
Report Period	October 1990–November 1991
Objectives	This report presents an analysis of infield completions and reserve growth potential in four Tertiary-age geologic units in the Gulf Coast Basin of South Texas. The infield well completions used to examine reserve growth were defined from a concurrent GRI project involving macro-scale analysis of gas production and prediction of reserve growth (Energy and Environmental Analysis, Inc., 1990). Development of the infield examples was designed to verify gas reserve growth volumes assessed in the macro-scale project and also complements the on-site testing programs performed for GRI, U.S. Department of Energy (DOE), and the Texas-funded Secondary Gas Recovery project.
Technical Perspective	Within-reservoir gas reserve growth can be defined as incremental production within a single reservoir by state-of-the-art, conventional methods, of natural gas in mature fields that was not accessed during original development of the fields because of geologic complexity, problems with log analysis, and interactions between regulatory controls, production strategies, and continuing technological advances. The relation between sandstone geometry, reservoir permeability, and well completion geometry is important to within-reservoir reserve growth in district 4. The extent to which partially and totally isolated compartments can be more readily found in fluvial and deltaic strata is determined by advanced understanding of sandstone geometry and technological advances. Reserve growth may result from improved well logging and seismic analysis that allow better correlation of stratigraphically and structurally complex strata. Targets are currently being successfully developed, confirming that supermaturely developed South Texas gas reservoirs have significant potential for reserve growth.
Results	Statistical analyses using a macro approach for prediction of reserve growth must account for stratigraphic and structural complexity as well as variations in production histories. In the EEA macro study, all the REUR values of different-sandstone, cycled, and same-sandstone completions within each class and density of reservoir section were grouped together. Such an approach results in a reserve growth estimate that includes both within-reservoir and new-pool volumes.

The reservoir-section types that contributed to the EEA infill reserve growth estimate were evaluated. Some 660 Bcf of EEA's estimate of 3,001 Bcf consists of gas volumes extrapolated using consolidated reservoir groups, cycled reservoirs, and reservoirs for which available data were determined to be incorrect. At least half of that volume should be removed from the estimate, in our judgment. A total of 334 Bcf was extrapolated from reservoir sections representing rate acceleration in wells draining gas volumes probably already contacted and should also be removed from the reserve growth estimate. Thus, 78 percent (2,337 Bcf) of the initial estimate of 3,001 Bcf has been validated by this study. The validated volume has been further disaggregated to define contributing components.

One component of the EEA estimate includes reservoir volumes from the Wilcox Lobo trend, a major low-permeability trend where limited drainage radii lead to expected reserve growth. The potential for incremental recovery in such low-permeability (tight) reservoirs is now becoming more widely recognized. The remaining portion of the estimate is composed of 1,115 Bcf that represents within-reservoir reserve growth, and 579 Bcf that represents shallower- or deeper-pool reservoirs determined not to be in pressure communication with preceding completions in a given reservoir section but nevertheless contributing to overall reserve growth.

Thus, of an original, low-end estimate (developed by EEA) of 3,001 Bcf in four stratigraphic units in district 4 of South Texas, two-thirds of that volume was estimated to represent reserve growth in predominantly conventional-permeability reservoirs (2,024 Bcf), and more than one-third (1,115 Bcf), or 37 percent, was estimated to represent reserve growth within the same reservoir section. On a larger scale, these results validate 78 percent, or 5.6 Tcf, of a high-end infill estimate (developed by EEA) of 7.2 Tcf for nine stratigraphic units in district 4. This is a significant resource volume given the historical expectation that natural gas can be efficiently drained with widely spaced wells (1 or 2 per square mile) in conventional reservoirs.

Project results indicate that the use of reported reservoir nomenclature and perforation data must be verified by at least a sampling of geological and engineering data from the fields involved in order to disaggregate reserve growth estimates and to understand their contributing components. The distinction between total reserve growth and within-reservoir reserve growth due to depositional and diagenetic heterogeneity must remain clear in any discussion of reserve growth processes and estimates. Similarly, reserve growth in tight reservoirs must be recognized as a different phenomenon and as a valid component of reserve growth.

Technical Approach

The data in this report are composed of groups of infield completions from nonassociated gas reservoirs in Railroad Commission of Texas district 4, South Texas. Each group of completions is reported to be from a single reservoir and within a 1-mi^2 (640-acre) area or reservoir section. Stratigraphy of the Frio and Vicksburg Formations, Wilcox Group, and Miocene-age strata in these sections was examined using depositional systems analysis of geophysical well logs and production and pressure analyses. Pressure analyses made using bottom-hole pressures and reservoir volumes were calculated using standard petroleum engineering relationships and software provided by Research Engineering and Consultants, Inc., of Denver, Colorado, a contractor on the Secondary Gas Recovery project. Reservoir sections indicating reserve growth were grouped by play, and estimated ultimate recovery of the last well (youngest well completed in the reservoir section) and recovery ratios (ratio of the estimated ultimate recovery of the last well to the average of estimated ultimate recoveries of all previous wells in the reservoir section) were used to determine the nature of reserve growth on a play basis.

Project Implications

Accurate estimates of reserve growth are important for GRI in determining its future research program and for providing industry with an estimate of how much additional low-cost gas can be accessed from existing gas fields. GRI funded a statistical study of public domain production records to determine the remaining reserve growth potential in districts 4 and 8 of Texas (GRI Report 91/1111). Concurrently, GRI has funded research in the Joint Venture for Infield Reserve Growth in conjunction with the U.S. Department of Energy and the State of Texas. The Joint Venture is designed to give operators guidelines and examples of how to best deploy state-of-the-art technology to access within-reservoir reserves that are not being tapped with current development practice. As such, the project is very detailed in its analysis of individual gas fields and reservoirs.

The project described by the attached report is designed to bridge the gap between detailed field studies of the Joint Venture and the macro/statistical analysis of the prior GRI reserve growth assessment study. By providing infield examples to verify gas reserve growth, this project examines the accuracy of the underlying data used in the macro-scale analysis of gas production and prediction of reserve growth. The macro study did the herculean job of converting all well location data to a township-range system, estimating ultimate recovery of each well completion and assigning of uniform formation names. But it still relied on the accuracy of operator designation of reservoir names that are known to contain some amount of error. By defining the magnitude of this error, the study presented herein shows that although reserve growth is significant, macro estimates of within-reservoir reserve growth must be reduced to account for errors in reservoir designation. Likewise, errors due to faulty data and incorrect compensation for gas cycling also cause the macro estimate to be too large.

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INTRODUCTION

South Texas (Railroad Commission of Texas district 4) has the largest annual gas production of any lower-48 region, totaling 1.2 Tcf of gas in 1990 (Energy Information Administration, 1990). Infield drilling in known reservoirs in South Texas could increase natural gas reserves by about 15 percent of estimated ultimate recovery (Finley and others, 1988). This report, funded by the Gas Research Institute (GRI), presents an analysis of infield completions and reserve growth potential in four Tertiary-age geologic units in the Gulf Coast Basin of South Texas.

The relation between sandstone geometry, reservoir permeability, and well completion geometry is important to infield reserve growth in district 4. Unconformities within deltaic sandstones in Frio, Vicksburg, Wilcox, and Miocene strata have gone unrecognized until recent years, making recorrelation using modern seismic data profitable. Long gross perforation intervals (perforations spanning several hundred feet) in downdip, lower permeability, deltaic sandstone units make productive infill wells. Updip, completions in high-permeability, structurally simple but depositionally complex fluvial-deltaic sandstones tap compartments in partial or total isolation from previously tapped sandstones within a single reservoir.

The extent to which partially and totally isolated compartments can be more readily found in fluvial and deltaic strata is determined by advanced understanding of sandstone geometry and by technological advances. Volumes of reserve growth resulting from improved well logging and seismic analysis that allow better correlation of stratigraphically and structurally complex strata are both difficult to estimate and highly dependent upon technological progress. These targets are currently being successfully developed, confirming that supermaturely developed (more than 40 years old) South Texas gas reservoirs have significant potential for reserve growth (Kerr, 1990; Langford and others, in press).

The infield well completions used to examine reserve growth in this study were defined from a concurrent GRI project involving macro-scale analysis of gas production and prediction of reserve growth (Energy and Environmental Analysis, Inc., 1991). Development of the infield examples in this study was designed to verify gas reserve growth volumes assessed in the macro-scale project and to complement the on-site testing programs performed during the Secondary Gas Recovery (SGR) project funded by GRI, the U.S. Department of Energy (DOE), the State of Texas, and industry partners.

A gas reserve growth volume of 3,001 Bcf was predicted for South Texas in the macro-scale analysis. This estimate relies almost entirely on reservoir designations and gas volumes reported to the Railroad Commission of Texas and on well locations given on scout tickets from the 1960's to the present. These data reflect efforts to be accurate at the time they were reported, but they do not reflect changes in reservoir designations and petroleum production methods and regulations that have occurred over the years and they cannot compensate for unintentional errors and survey inaccuracy. For example, reservoir sandstones in wells believed to be in complete and total communication in the early stages of field development have been shown in later years to contain many reservoir compartments, some of which were only partially tapped by older wells. This study assesses the accuracy of the reported data used in the macro-scale analysis and the effect of irregularities in these data on the macro-scale gas reserve growth prediction.

DEFINITION OF GAS RESERVE GROWTH

Gas reserve growth is defined in this report as incremental production within a single reservoir in mature fields by state-of-the-art conventional methods. This natural gas was not accessed during primary development of the fields because of geologic complexity, problems with log analysis, and interactions between regulatory controls, production strategies, and continuing technological advances (Langford and others, in press). Mature fields are those in which discovery, definition of field limits, and development of relatively complete well patterns have taken place and annual production is at a plateau or falling. Field boundaries are generally well defined, although advanced geophysics may yet define extension opportunities. Gas reserve growth does not include completions that are in pressure communication with existing wells (rate acceleration), nor is it gas produced using water or carbon dioxide (CO_2) injection or other techniques such as coproduction of gas and large volumes of water.

This study primarily concerns identifying reserve growth from well completions in discrete, geologically defined mature reservoirs. Although the reservoirs may appear to be continuous and their boundaries known, additional completions may contact incompletely drained or untapped compartments (fig. 1). Reserve growth not considered in this report may also come from isolated sandstones in newly designated, previously unproduced reservoirs (bypassed reservoirs), typically at shallower depths than the original reservoir completion of a given well.

METHODOLOGY

Data used in this report are groups of infield completions from nonassociated gas reservoirs in Railroad Commission of Texas district 4, South Texas (fig. 2). The completion examples were defined from a concurrent GRI project involving macro-scale analysis of gas production. A description of the methodology used in that analysis, performed by Energy and Environmental Analysis, Inc. (EEA), appears in appendix A. The terms PPY and REUR, defined in appendix A, were used by EEA to evaluate incremental gas production from existing completion groups. One important characteristic of PPY values is that they are not equivalent between 2-well and 4-well reservoir sections. The reader is encouraged to consult appendix A before continuing further in this report.

Each group of completions is reported to be from a single reservoir and within a 1-mi^2 (640-acre) area or reservoir section. Stratigraphy of the Frio and Vicksburg Formations, Wilcox Group, and Miocene-age strata in these sections was examined using depositional systems analysis of geophysical well logs and production and pressure analyses to determine the appropriateness of the data for prediction of gas reserve growth. Reservoir sections indicating reserve growth were grouped by play, and estimated ultimate recovery of the last well (youngest well completed in the reservoir section) and recovery ratios (ratio of the estimated ultimate recovery of the last well to the average of estimated ultimate recoveries of all previous wells in the reservoir section) were used to determine the nature of reserve growth on a playwide basis.

Reservoir engineering and production characteristics were obtained from the Railroad Commission of Texas Central Records department and Dwights Energydata, Inc., of Richardson, Texas. Pressure analyses made using bottom-hole pressures and reservoir volumes were calculated using standard

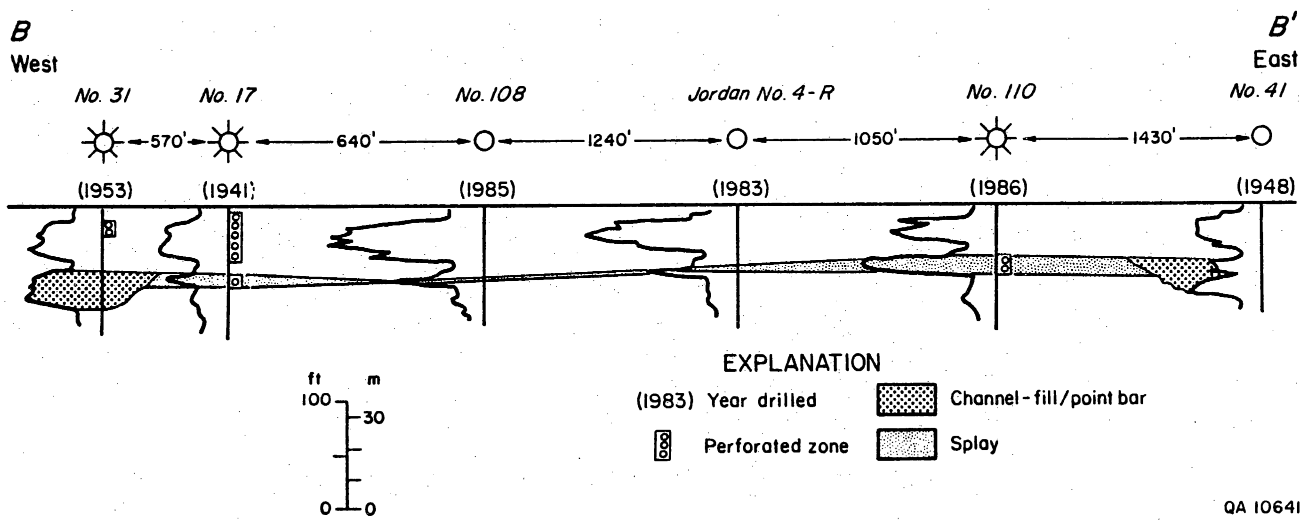

Figure 1. Stratigraphic dip cross section showing S.P. logs of La Gloria Gas Units completed in a single, geologically defined reservoir in La Gloria field, South Texas. Mobil #110 La Gloria Gas Unit, an infield completion made in 1986, produced from a sandstone that was partially isolated from other productive sandstones in the reservoir. Well #110 came in at five times expected (current average) reservoir pressure and 45 percent original reservoir pressure. Total production for the well was 0.05 Bcf. From Jackson and others (1990).

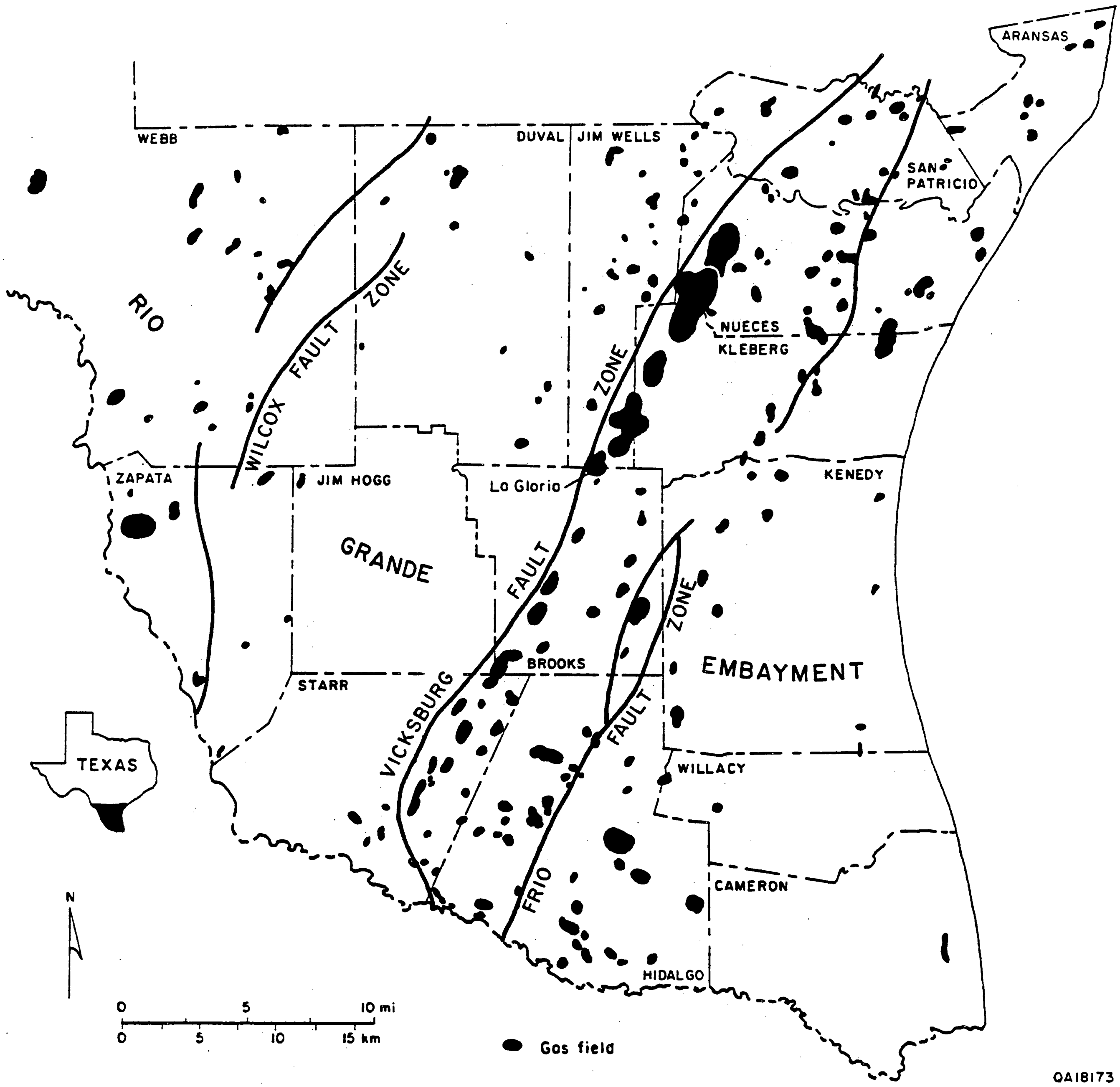

Figure 2. Distribution of fields that contain well completions examined in Railroad Commission of Texas district 4. Field sizes are approximate.

petroleum engineering relationships and software provided by Research Engineering and Consultants, Inc. (REC) of Denver, Colorado, a contractor on the Secondary Gas Recovery project.

GEOLOGIC SETTING AND PLAY CHARACTERISTICS

The Oligocene Frio and Vicksburg Formations, the Paleocene-Eocene Wilcox Group, and Miocene strata form large siliciclastic progradational wedges that dip gradually toward the Gulf of Mexico shoreline and into the Gulf Coast Basin in South Texas (figs. 2 and 3). These fluvial, deltaic, and barrier/strandplain strata were deposited in the basin axis and along the margins of the Rio Grande Embayment. The Frio Formation is the most areally extensive of these sediment wedges that thicken across the Wilcox, Vicksburg, and Frio Fault Zones. Miocene gulfward thickening occurs primarily in the offshore region (fig. 3). Gas-prone, fluvial, deltaic, and barrier/strandplain reservoirs in these strata are elongate parallel to regional fault zones, where hydrocarbons are trapped in rollover anticlines adjacent to growth faults. Early explorationists developed these structural traps. Today, new gas in these mature fields can be found by refining earlier stratigraphic correlations and exploring for lateral and vertical stratigraphic traps controlled primarily by the heterogeneity of diagenesis and original depositional systems and secondarily by faulting. The emphasis in this project is on compartmentalization potential inherited from original depositional processes, because diagenetic and structural heterogeneities are impossible to determine using currently available technologies and the data available in this study.

Frio Formation

The Frio Formation in South Texas was deposited in a large passive margin basin characterized by rapid subsidence. Frio sediments are cut by large-scale, down-to-the-coast faults and contain intrastratal deformation (figs. 3 and 4). Updip portions of the Frio dip gently and uniformly basinward, while downdip from the Vicksburg Fault Zone the section thickens rapidly and structures become increasingly complex (Galloway and others, 1982).

The Frio Formation is divided into eight gas plays in district 4 on the basis of depositional systems analysis (Kosters and others, 1989) (fig. 5). The most sandstone rich plays are the downdip

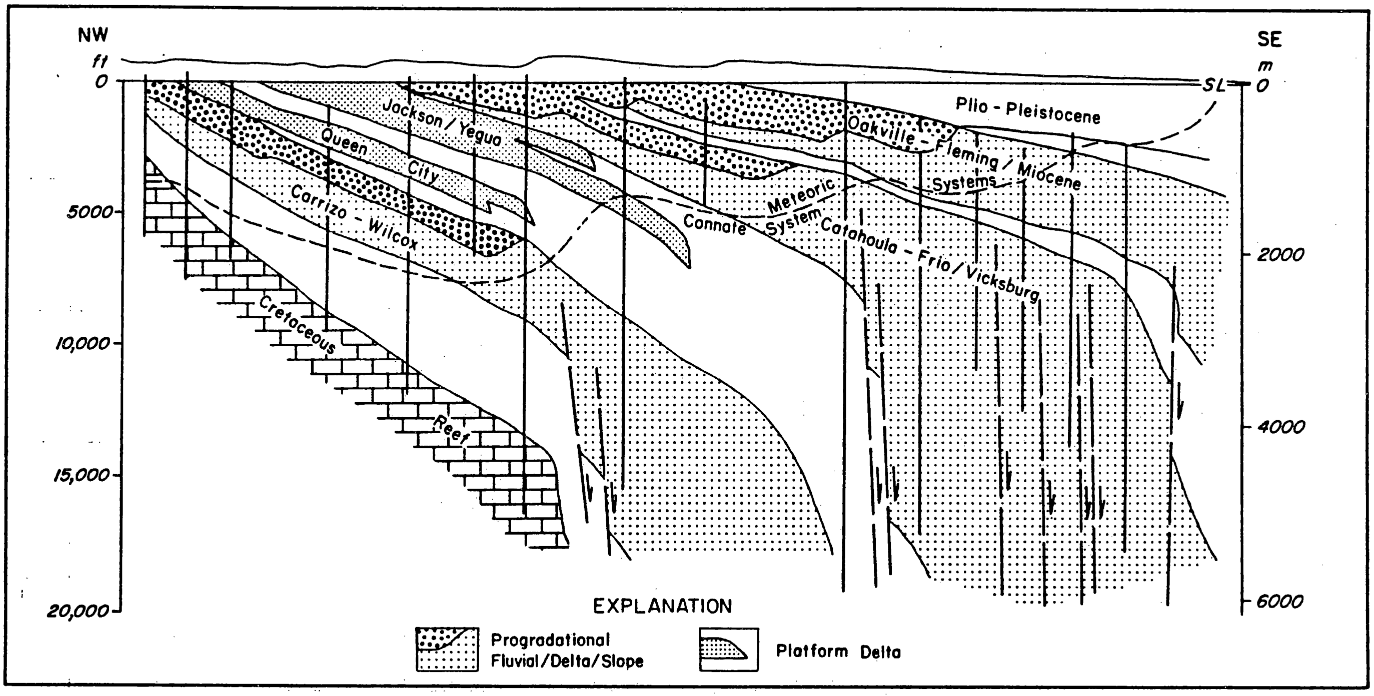

Figure 3. Schematic dip cross section illustrating the principal Tertiary progradational wedges, Wilcox, Frio/Vicksburg, and Miocene, in the Texas Gulf Coastal Plain. From Galloway and others (1982).

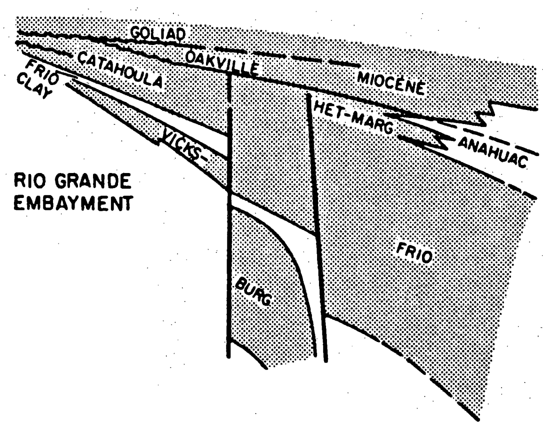

Figure 4. Schematic correlation section of the Rio Grande Embayment in South Texas, showing the stratigraphic relation between Vicksburg and Frio strata across the Vicksburg (left) and Frio (right) fault zones. From Galloway and others (1982).

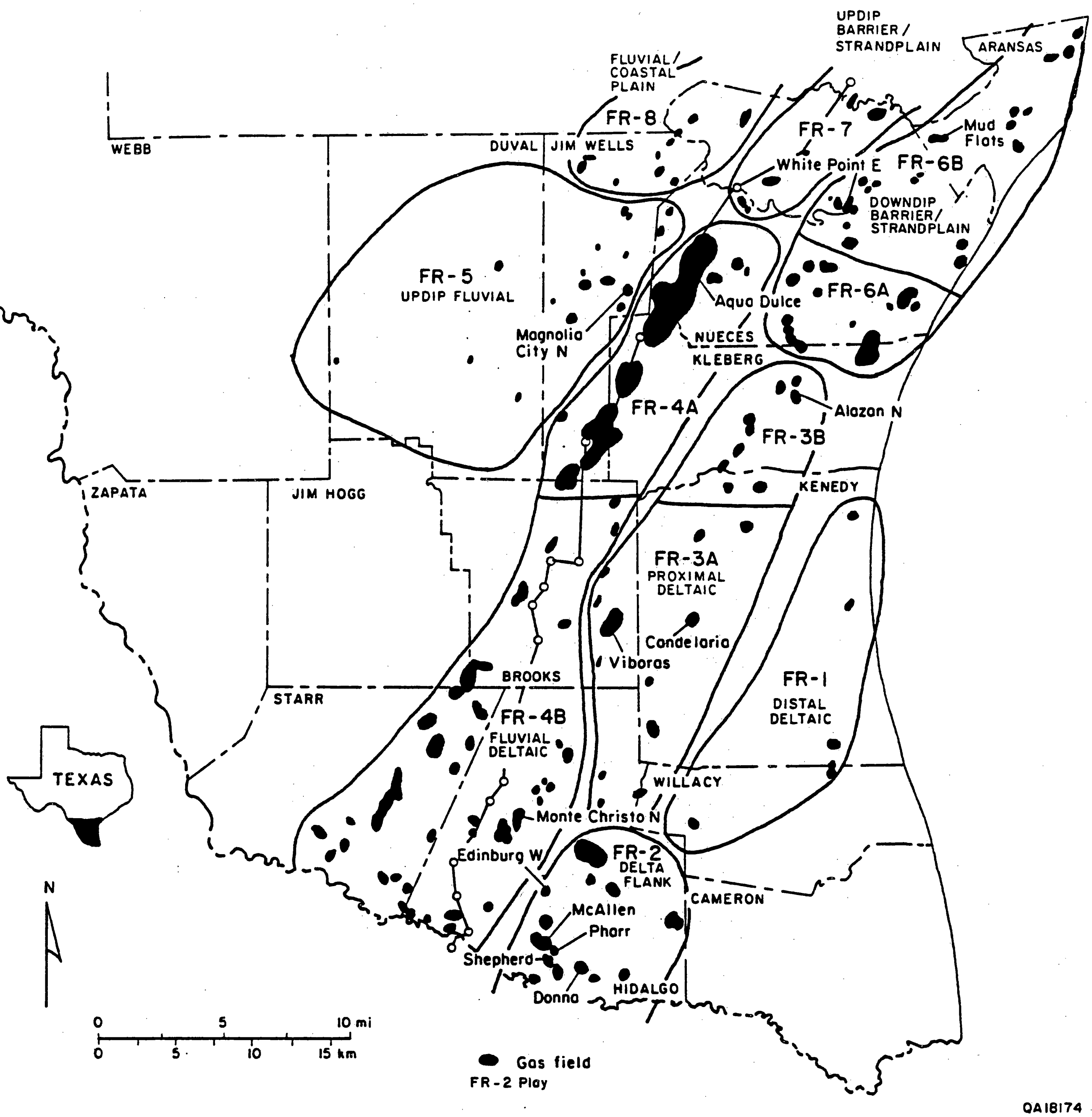

Figure 5. Frio fields that contain nonassociated gas reservoir sections of all densities having PPY values >10 and REUR values between 0 and 3. (See app. A for definitions of terms.) Plays are from Kosters and others (1989). Field sizes are approximate. Play boundaries including reservoirs not found in Kosters and others were made using depositional systems boundaries.

barrier/strandplain and delta-flank plays (plays 2 and 6) in the northern and southern parts of district 4, respectively (figs. 6 and 7). Sandstones in these plays are typically 50 to 100 ft thick and exhibit upward-coarsening and blocky SP-log traces. Barrier-island sandstones are relatively laterally continuous and contain large aquifers that actively support water-drive gas reservoirs (fig. 8). The fluvial-deltaic, proximal-deltaic, and distal-deltaic plays (plays 1, 3, and 4) also have relatively high sandstone-shale ratios. Updip portions of these plays contain moderately thick (30 to 100 ft) sandstones composed of multilateral and multivertical channel units (fig. 9). Downdip portions contain cyclic, upward-coarsening sandstone units that range from 100 to 400 ft in thickness (fig. 10). Downdip sections exhibit fault complexity, and gross correlations made without seismic control are limited in accuracy. The updip barrier/strandplain, updip fluvial, and fluvial/coastal plain plays (plays 5, 7, and 8) contain the least sandstone rich sediments (Galloway and others, 1982). These plays are characterized by thin (10 to 30 ft thick) sandstones that are less laterally continuous in the fluvial sections than in the barrier-island sections (fig. 11).

Vicksburg Formation

The Vicksburg Formation underlies the Frio Formation and similarly was deposited in a rapidly subsiding basin. Vicksburg strata are extensively growth faulted across the Frio Fault Zone, where sediment thickness expands more than 10 times (fig. 4) (Kosters and others, 1989). Principal Vicksburg gas production is from thick intervals of deltaic sandstones in rollover anticlines on the downdip side of the Vicksburg Fault Zone.

The Vicksburg Formation constitutes a deltaic play in district 4, composed of both dip- and strike-aligned sandstone geometries deposited in fluvial- and wave-dominated delta systems (fig. 12). Updip and downdip sandstones in this play exhibit characteristics similar to fluvial-deltaic and deltaic Frio plays, respectively. Updip reservoirs are relatively thin; sandstones average about 30 ft in thickness (fig. 13), whereas downdip reservoirs are composed of 100- to 600-ft-thick, blocky, and upward-coarsening sequences deposited in delta-front and nearshore-marine environments (fig. 14). Fault density increases with depth (Kosters and others, 1989), and downdip units contain multiple unconformities.

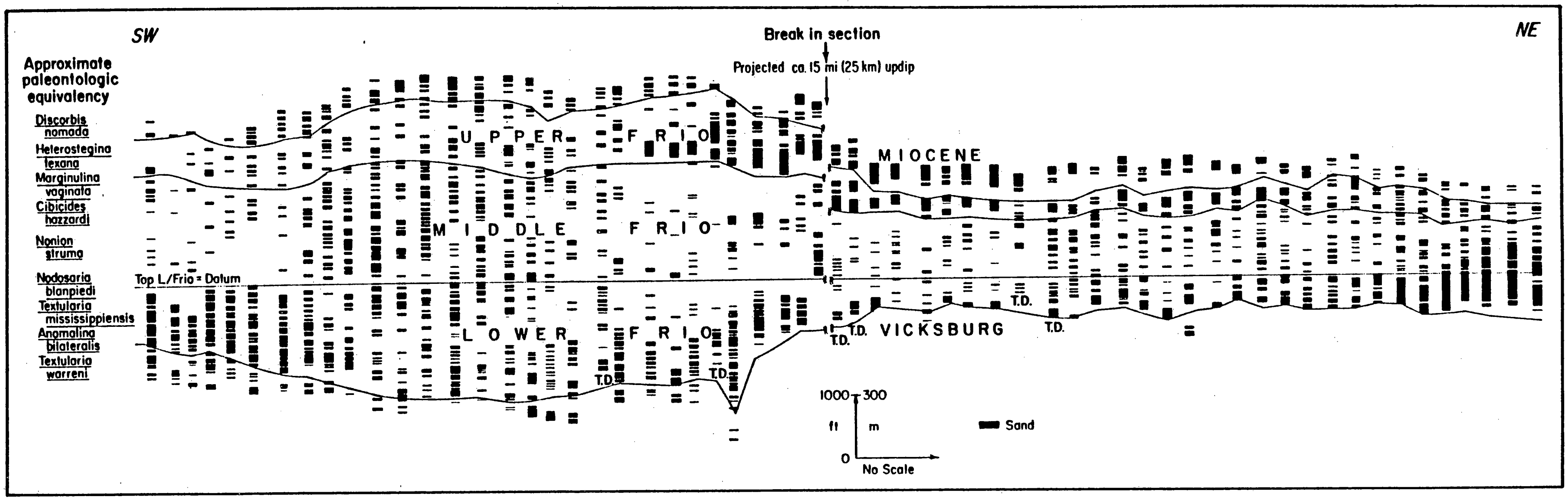

Figure 6. Regional composite strike section of the Frio Formation, Texas. Left half of section up to three wells southwest of the break in section is in district 4; see figure 5 for cross-section location. Within district 4, the thickest sandstones are distributed in the northeastern part of the upper Frio and in the southwestern part of the lower Frio, corresponding with the FR-6 (barrier/strandplain) and FR-2 (delta-flank) plays. Relatively thick sandstones are also distributed in the central, deepest part of the basin, corresponding with the FR-4 (fluvial-deltaic) and FR-3 (proximal-deltaic) plays.

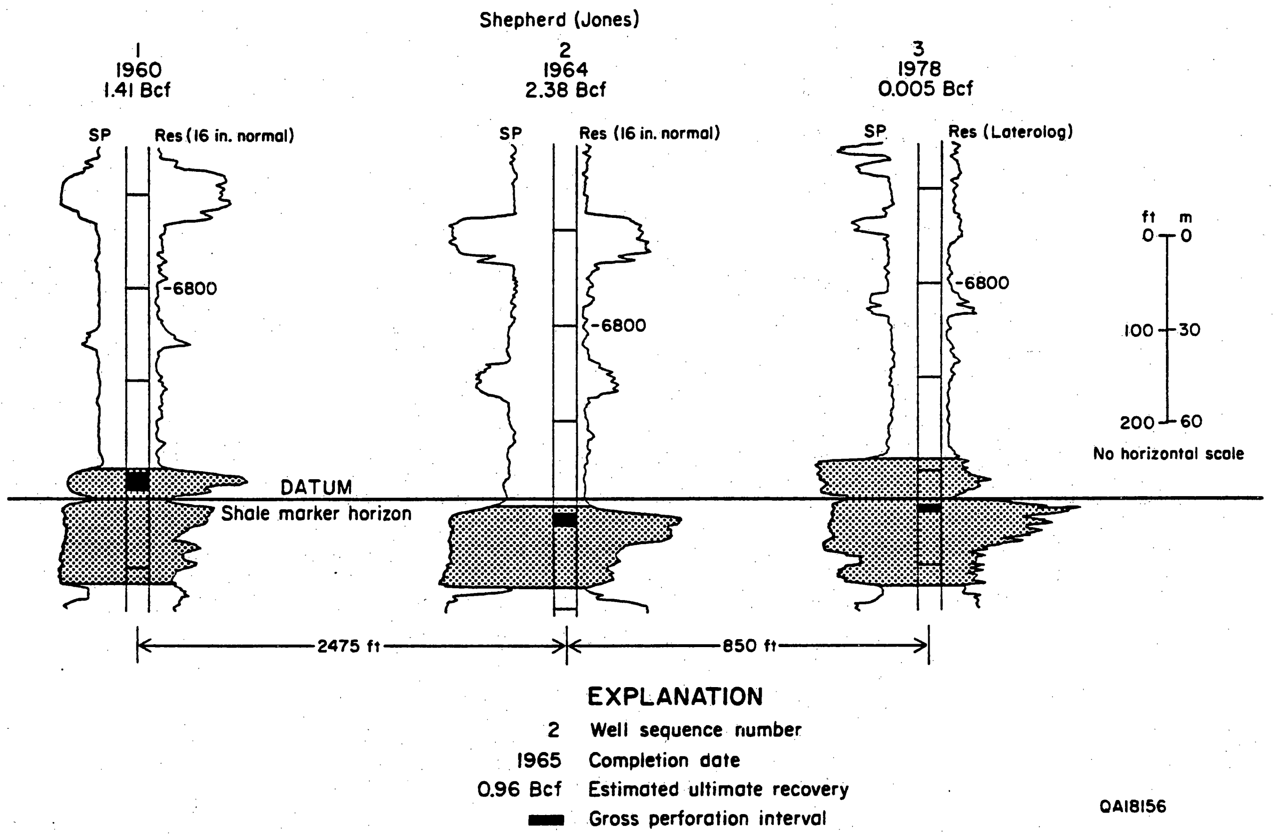

Figure 7. Reservoir section in Shepherd field, Jones reservoir, showing within-reservoir completions in a deltaic sandstone. REUR (see app. A for definition of this term) of this section is 0.0028. Field located in figure 5.

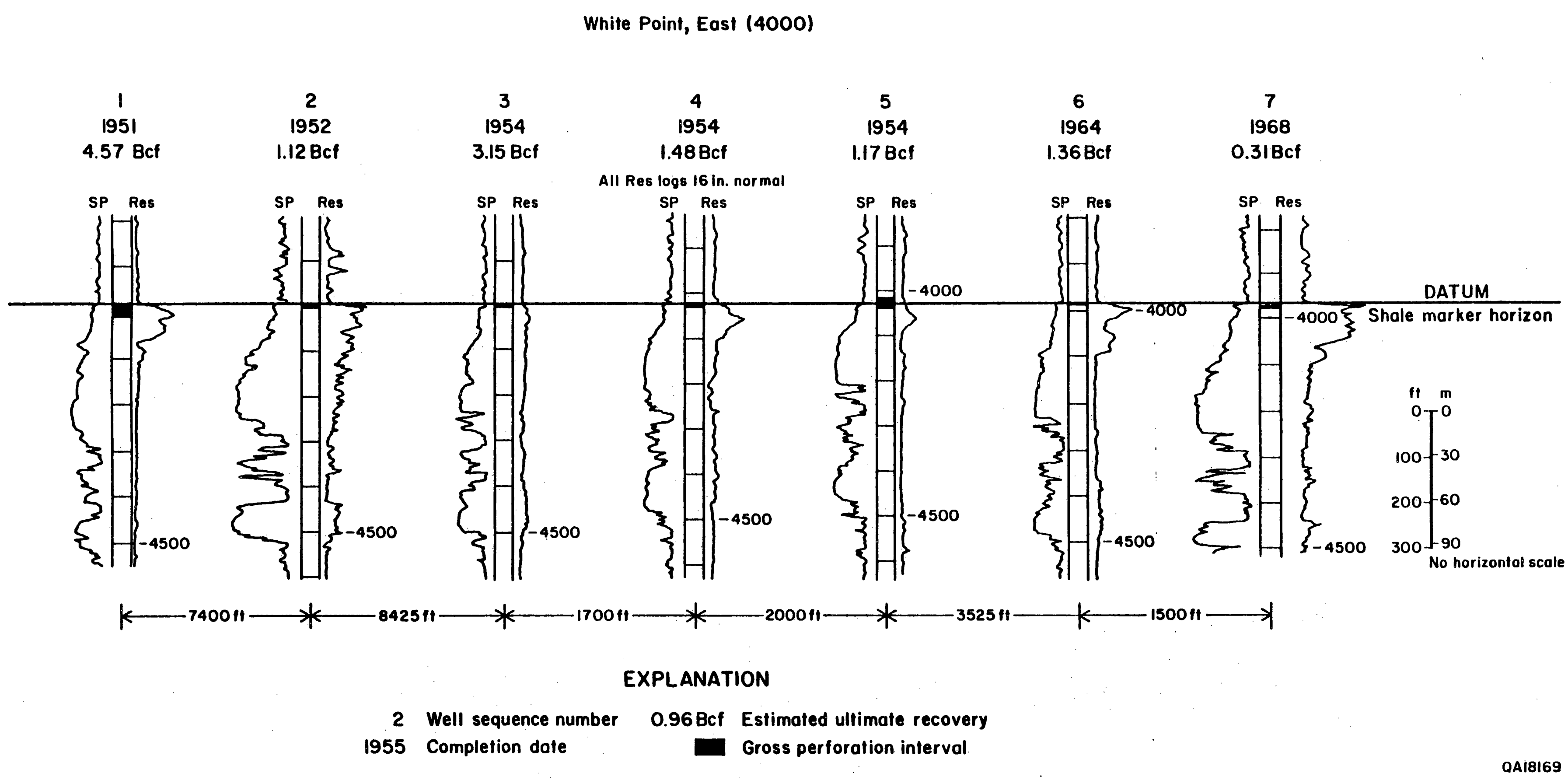

Figure 8. Reservoir section in White Point, East field, 4000 reservoir, showing perforations in thick, water-drive reservoir sandstones. REUR of this section is 0.15. Field located in figure 5.

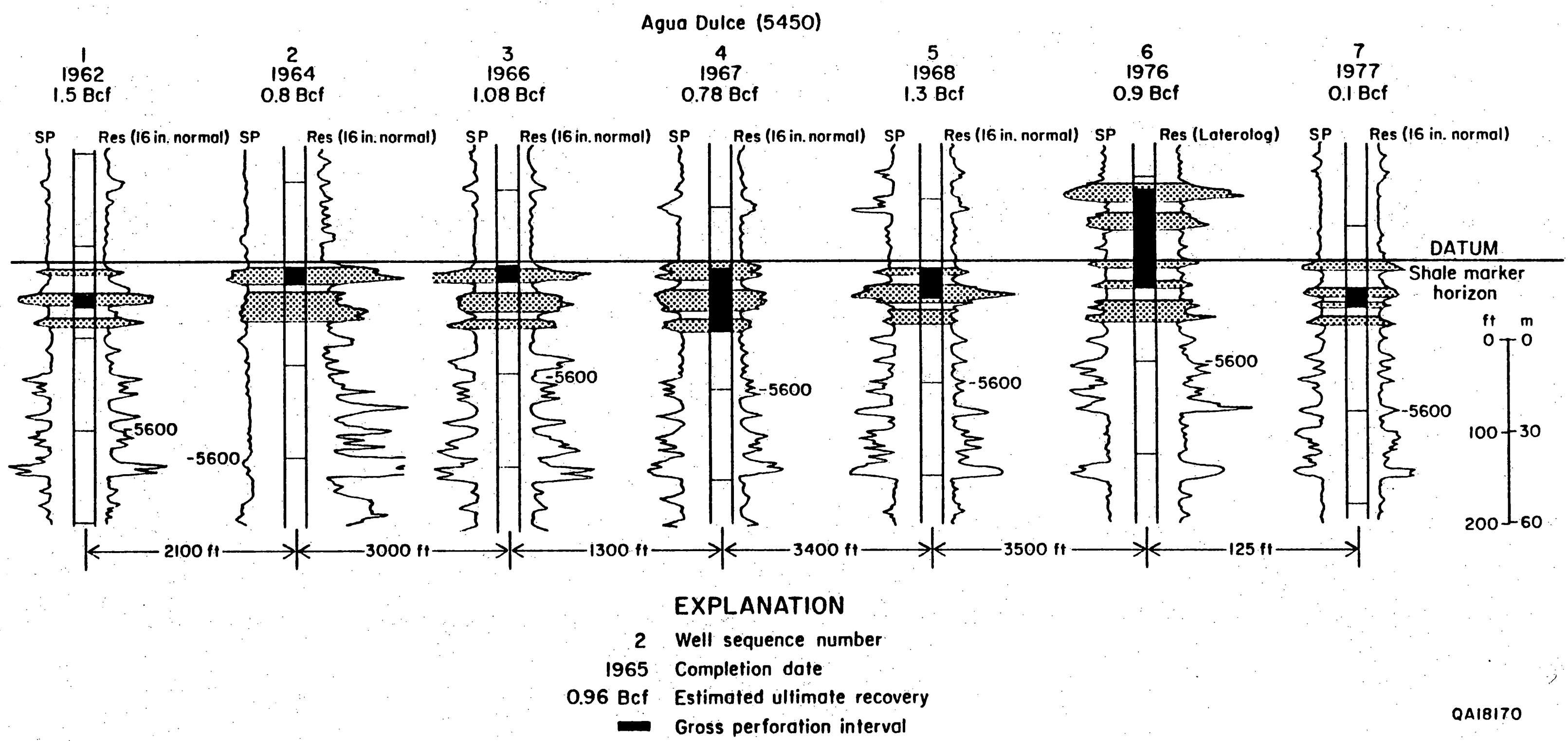

Figure 9. Reservoir section in Agua Dulce field, 5450 reservoir, showing perforations in multivertical fluvial channel sandstones. REUR of this section is 0.15. Field located in figure 5.

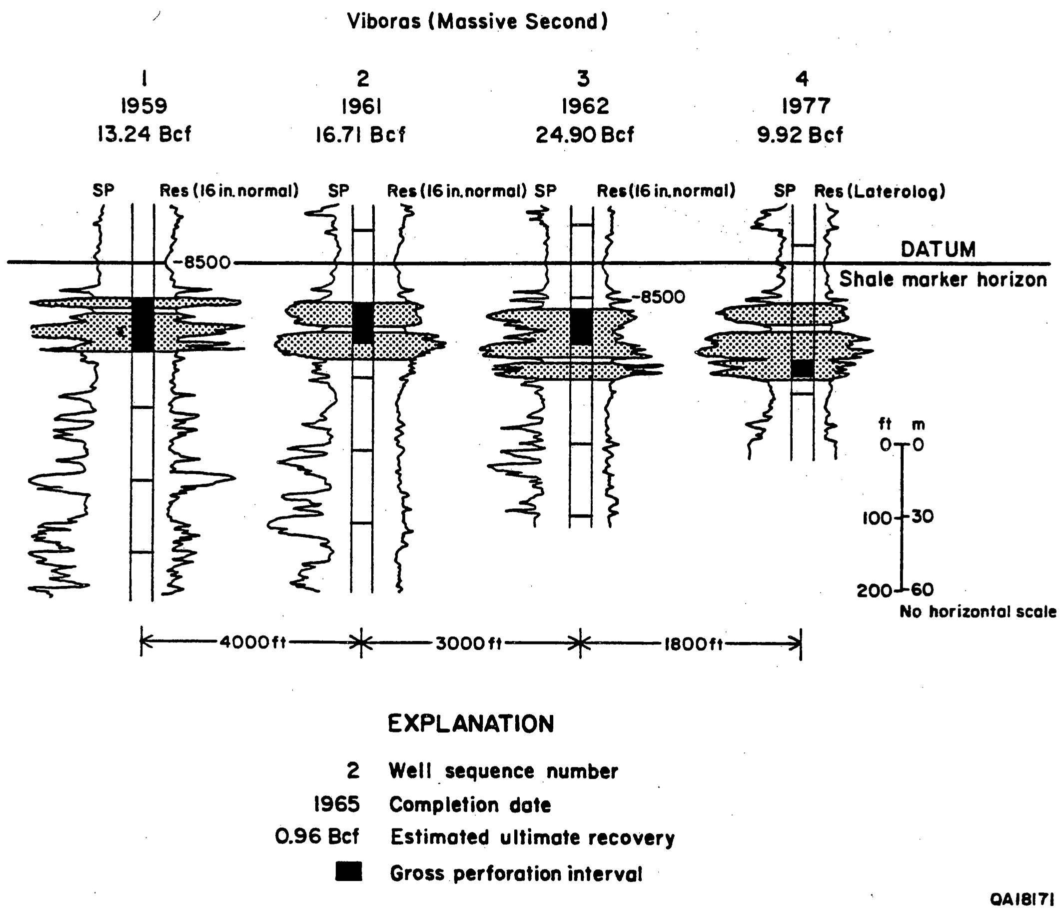

Figure 10. Reservoir section in Viboras field, Massive Second reservoir, showing perforations in multivertical distributary channel sandstones. REUR of this gas cycled reservoir section is 0.54. Field located in figure 5.

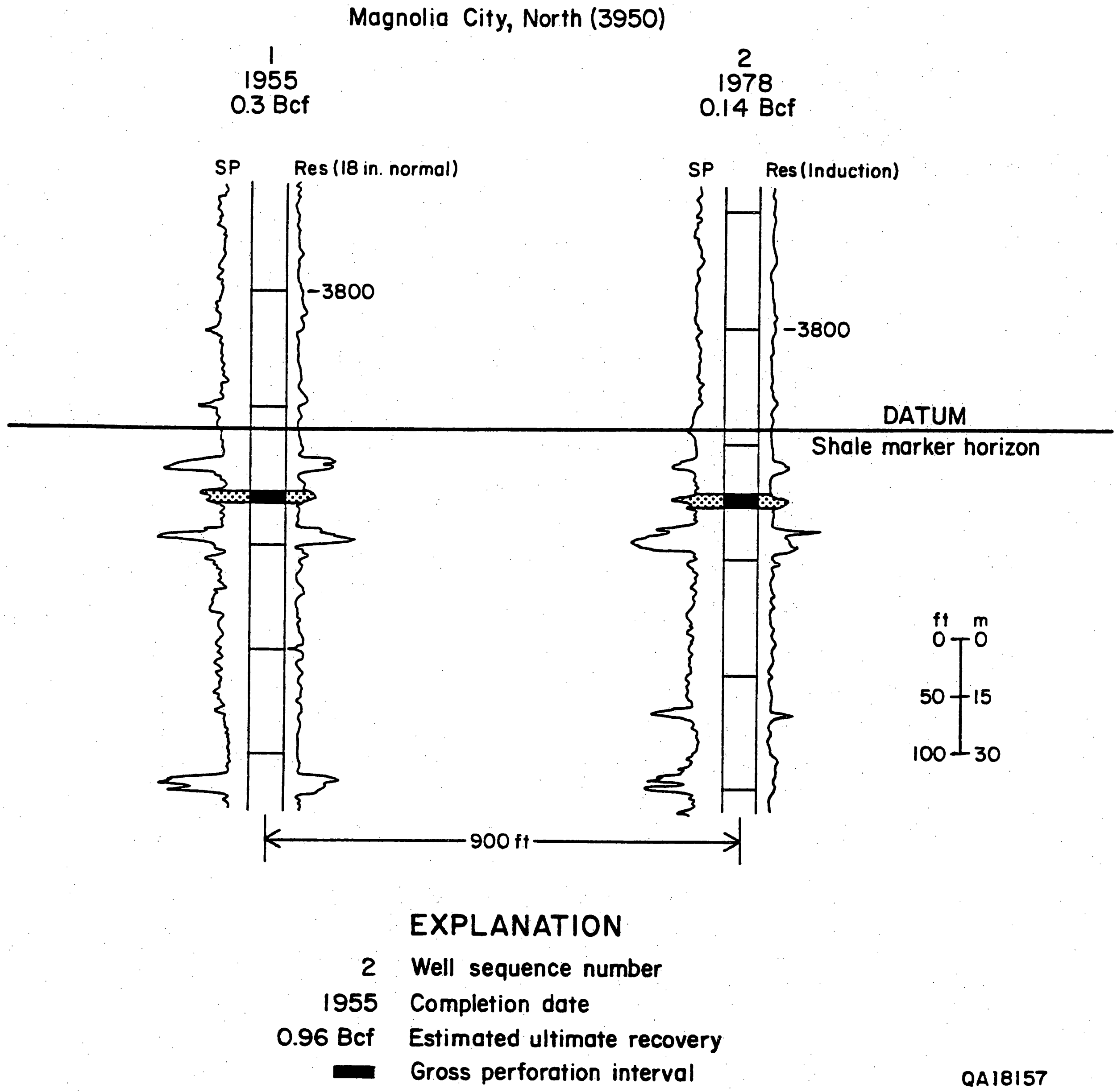

Figure 11. Reservoir section in Magnolia City, North field, 3950 reservoir, showing within-reservoir perforations in fluvial sandstones. REUR of this section is 0.47. Field located in figure 5.

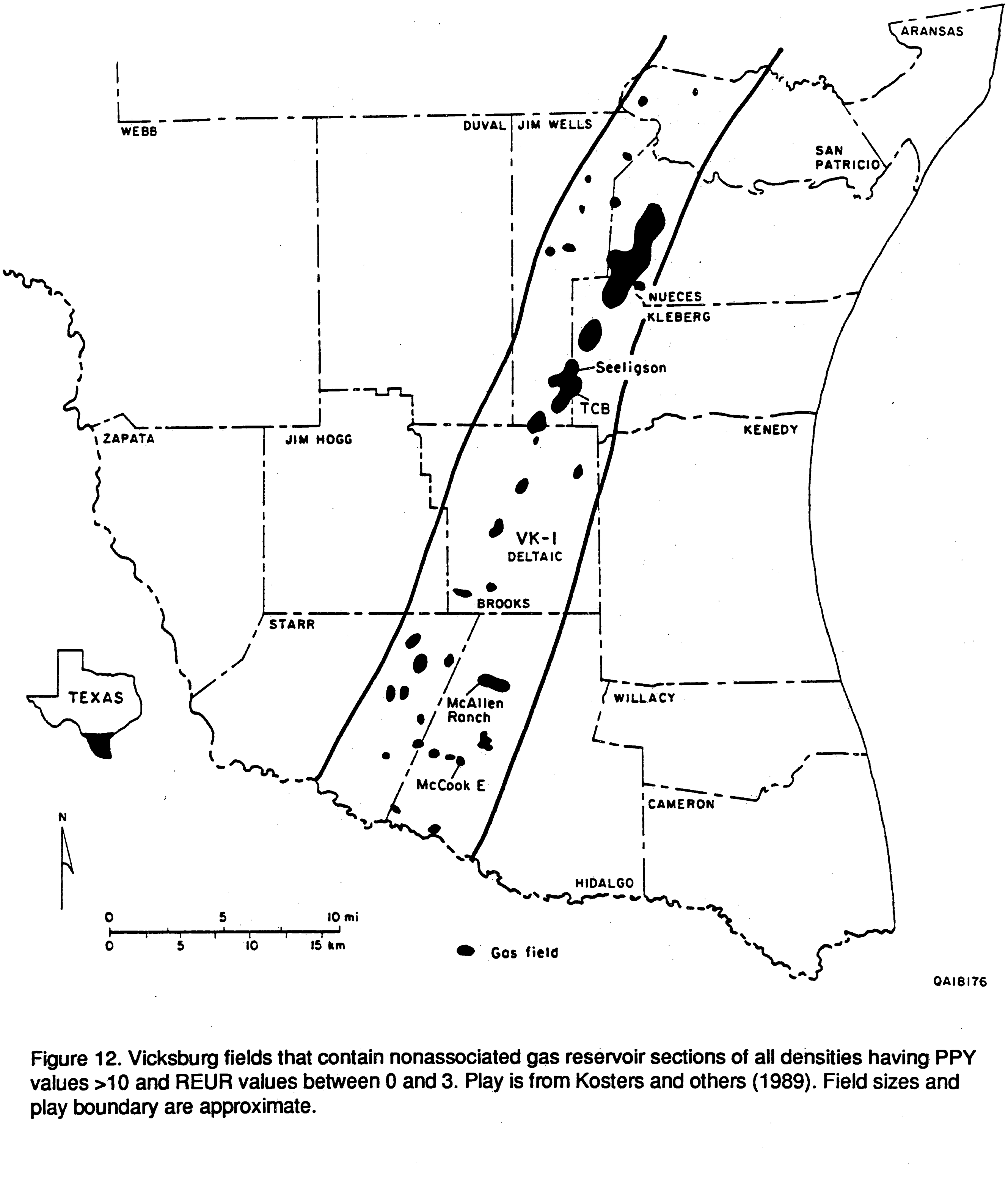

Figure 12. Vicksburg fields that contain nonassociated gas reservoir sections of all densities having PPY values >10 and REUR values between 0 and 3. Play is from Kosters and others (1989). Field sizes and play boundary are approximate.

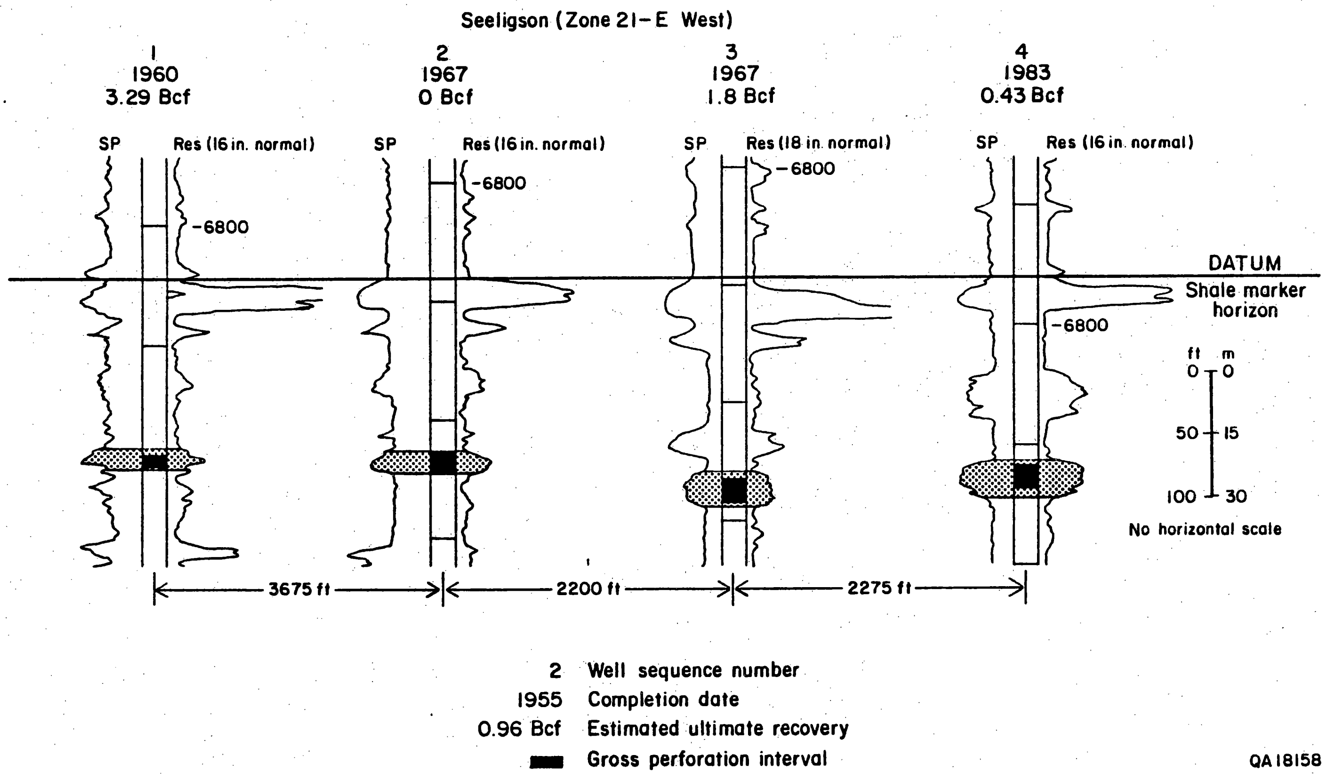

Figure 13. Reservoir section in Seeligson field, Zone 21-E West reservoir, showing within-reservoir perforations in proximal-deltaic sandstones. REUR of this section is 0.24. Field located in figure 12.

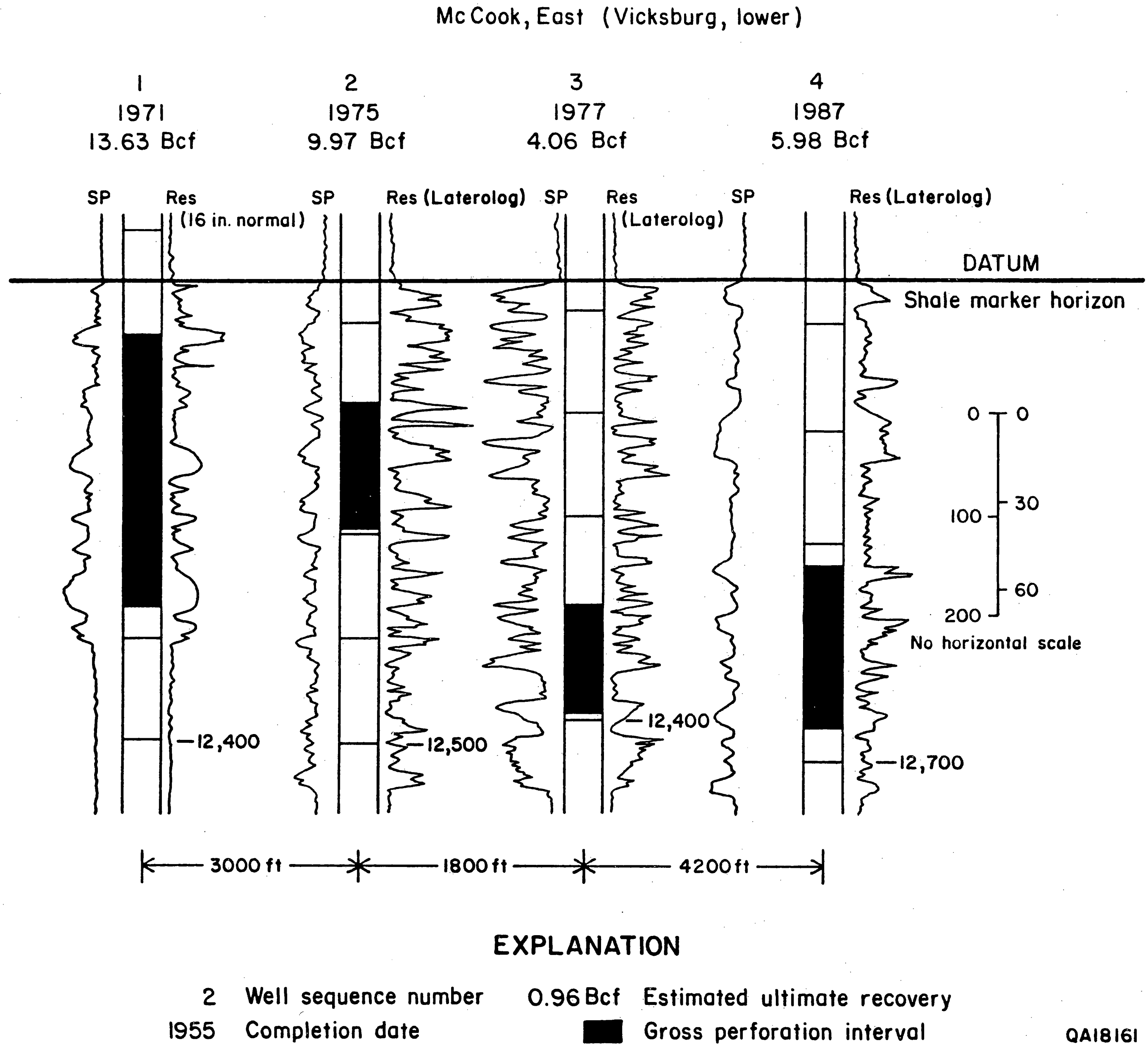

Figure 14. Reservoir section in McCook, E. field, Vicksburg lower reservoir, showing perforations in delta-front sandstones. REUR of this section is 0.64. Field located in figure 12.

Wilcox Group

Updip from the Vicksburg Fault Zone is the Wilcox Fault Zone (fig. 2), which localized sandstone accumulations along growth faults and today forms hydrocarbon traps in both upper and lower Wilcox deltaic sandstones. Updip, gently dipping upper Wilcox strata are relatively sandstone poor and trapped by faults associated with underlying Lower Cretaceous shelf margins.

Wilcox reservoirs in district 4 are divided into three plays, updip lower Wilcox, Wilcox Lobo, and Wilcox deltaic (fig. 15) (Kosters and others, 1989). Updip lower Wilcox reservoirs (play 3) were deposited on a coastal plain crosscut by local fluvial-deltaic systems (Kosters and others, 1989); the reservoir sections examined in this study, however, are primarily in deltaic strata (fig. 16). Wilcox Lobo reservoirs (play 2) were deposited in a rapidly subsiding basin, which resulted in multiple unconformities and stratigraphic complexity (fig. 17). Lobo reservoirs have low permeability, and Railroad Commission of Texas rules allow the combination of multiple, stacked sandstone reservoirs into a single productive unit. Play 4 contains Wilcox deltaic reservoirs located in the Wilcox Fault Zone. Reservoir sections in this play are primarily in upper Wilcox strata, characterized by wave-dominated delta systems and relatively laterally continuous delta-front and barrier-island sandstones (fig. 16) (Kosters and others, 1989).

Miocene Strata

Depositional systems of Miocene age in district 4 consist of the Santa Cruz fluvial system (play 2) and the North Padre delta system (play 1) (Galloway and others, 1986) (fig. 18). Reservoirs in these systems are shallow (except at the outer edge of the onshore area where Miocene strata are thickened by large-scale growth faults (play 1) (fig. 3) and produce from hydrocarbons and structural traps inherited from the underlying Frio and Vicksburg Formations (Kosters and others, 1989).

Miocene fluvial strata are interpreted as braided stream channels interlayered with thin floodplain shales (fig. 19). High permeabilities result in water-drive mechanisms for many Miocene onshore reservoirs (Kosters and others, 1989). Deltaic Miocene strata are represented in only three reservoir sections, located in thin, delta-destructional, transgressive sandstones and underlying thick delta-front and

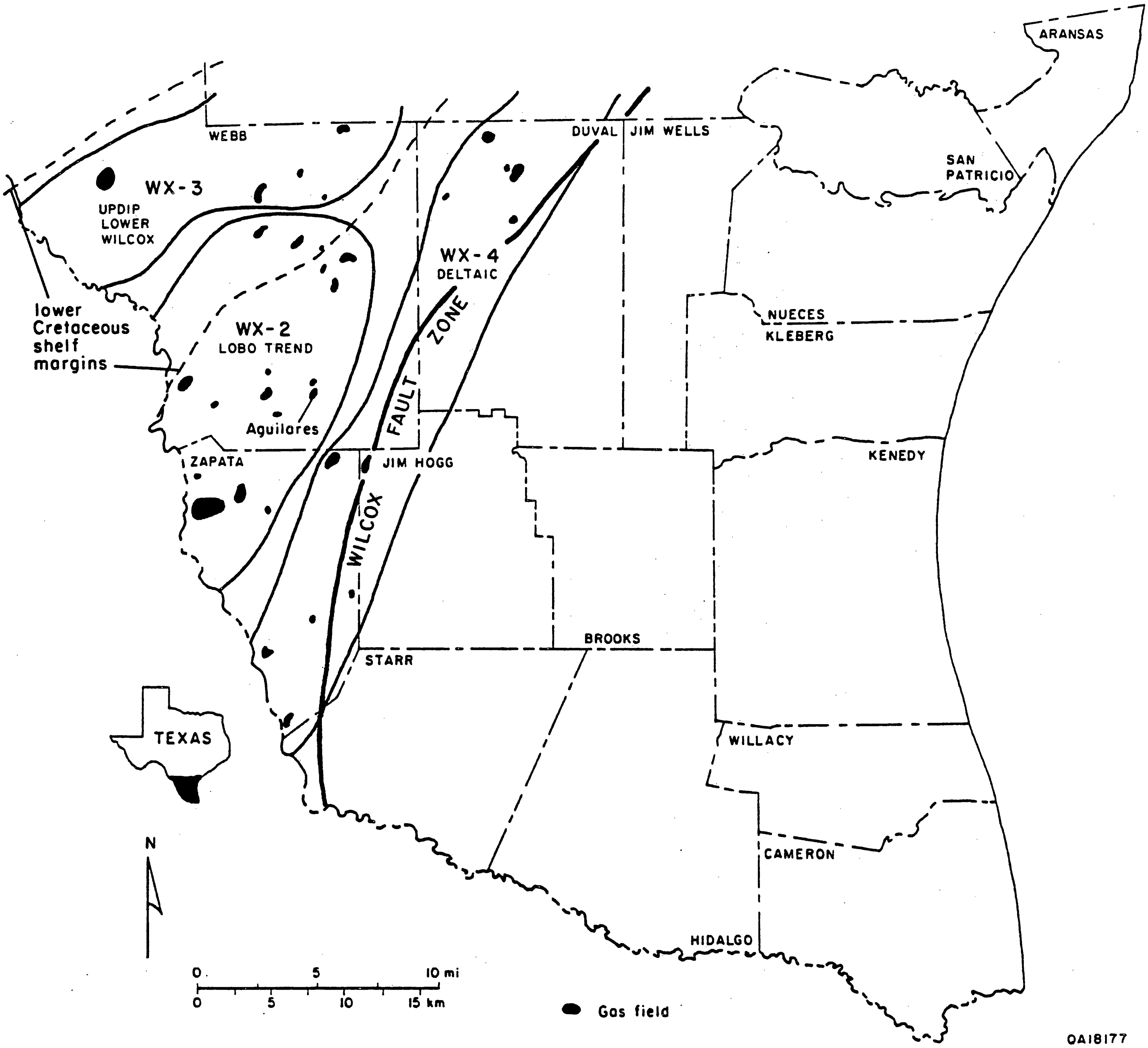

Figure 15. Wilcox fields that contain nonassociated gas reservoir sections of all densities having PPY values >10 and REUR values between 0 and 3. Plays are from Kosters and others (1989). Field sizes and play boundaries are approximate.

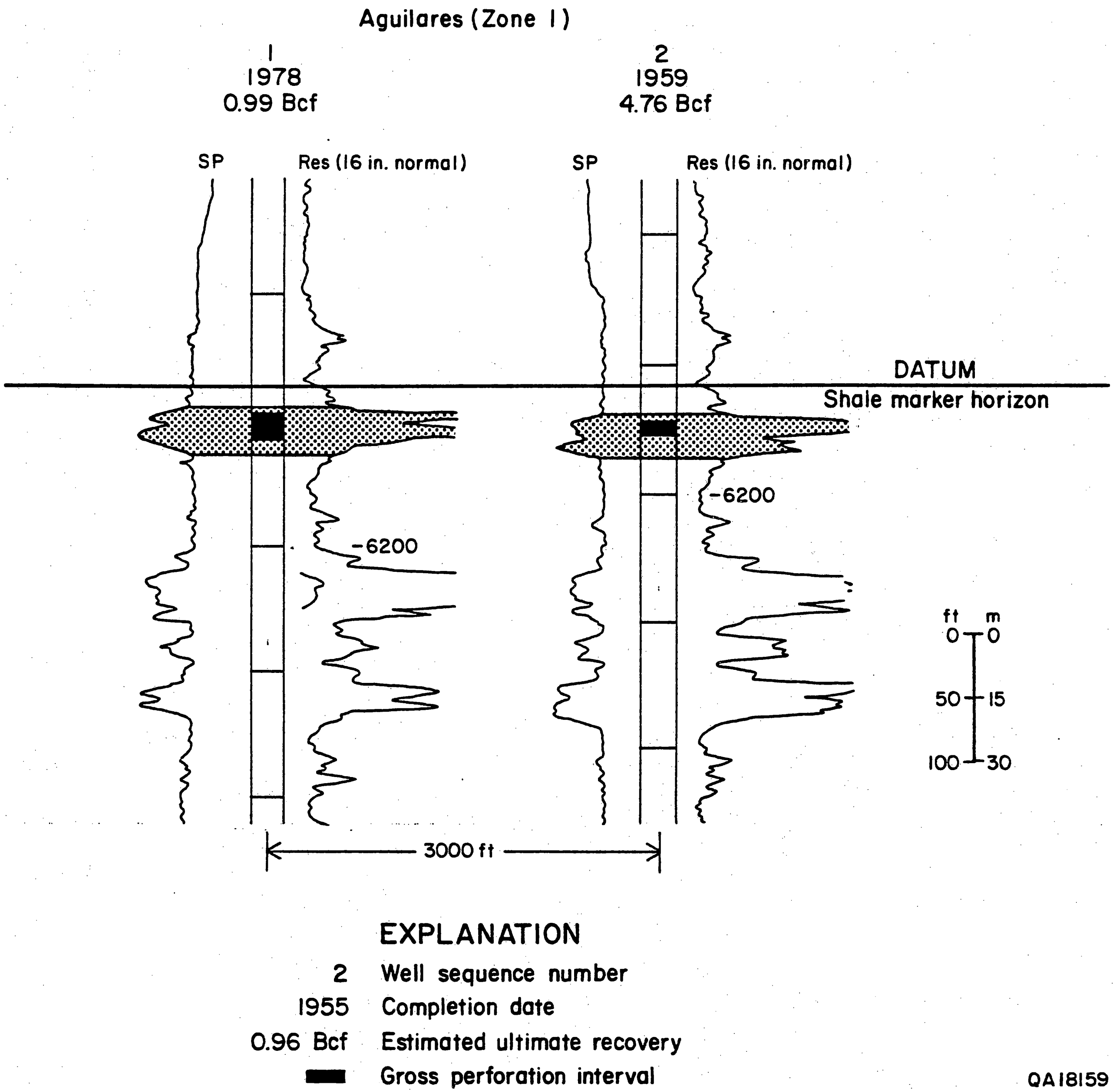

Figure 16. Reservoir section in Aguilares field, Zone 1 reservoir, showing within-reservoir perforations in deltaic sandstones. Although Aguilares field is located in the Wilcox Lobo play, the well log signatures of the Zone 1 reservoir are representative of both updip Wilcox reservoir sections to the northeast and Wilcox deltaic reservoirs downdip. REUR of this section is 0.21. Field located in figure 15.

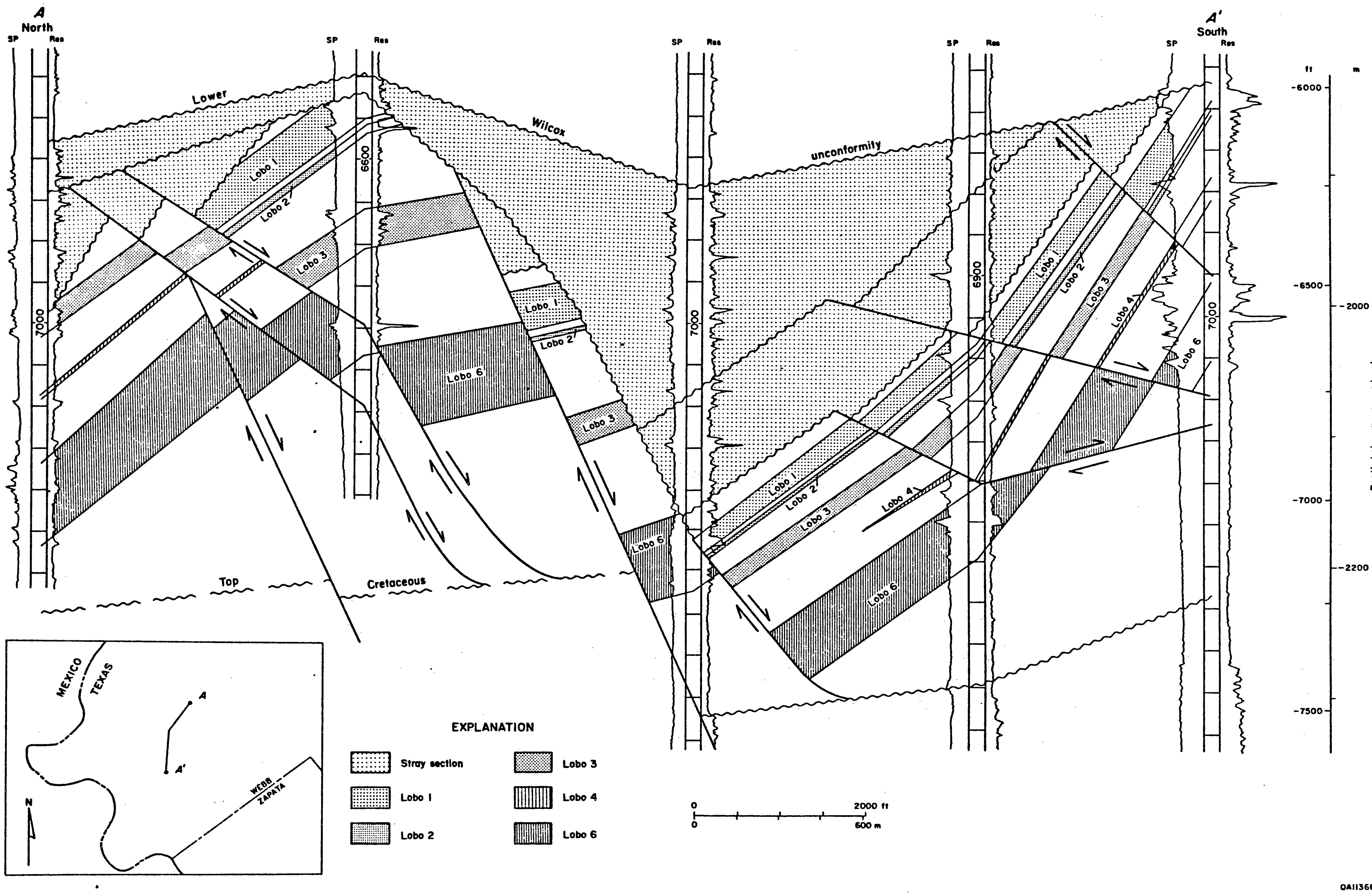

Figure 17. Complex Wilcox Lobo sandstone geometry interpreted in Laredo field. In many fields production from Lobo units 1-6 is combined into a single reservoir. From Kosters and others (1989), Railroad Commission of Texas Docket No. 4-67,530, 1977.

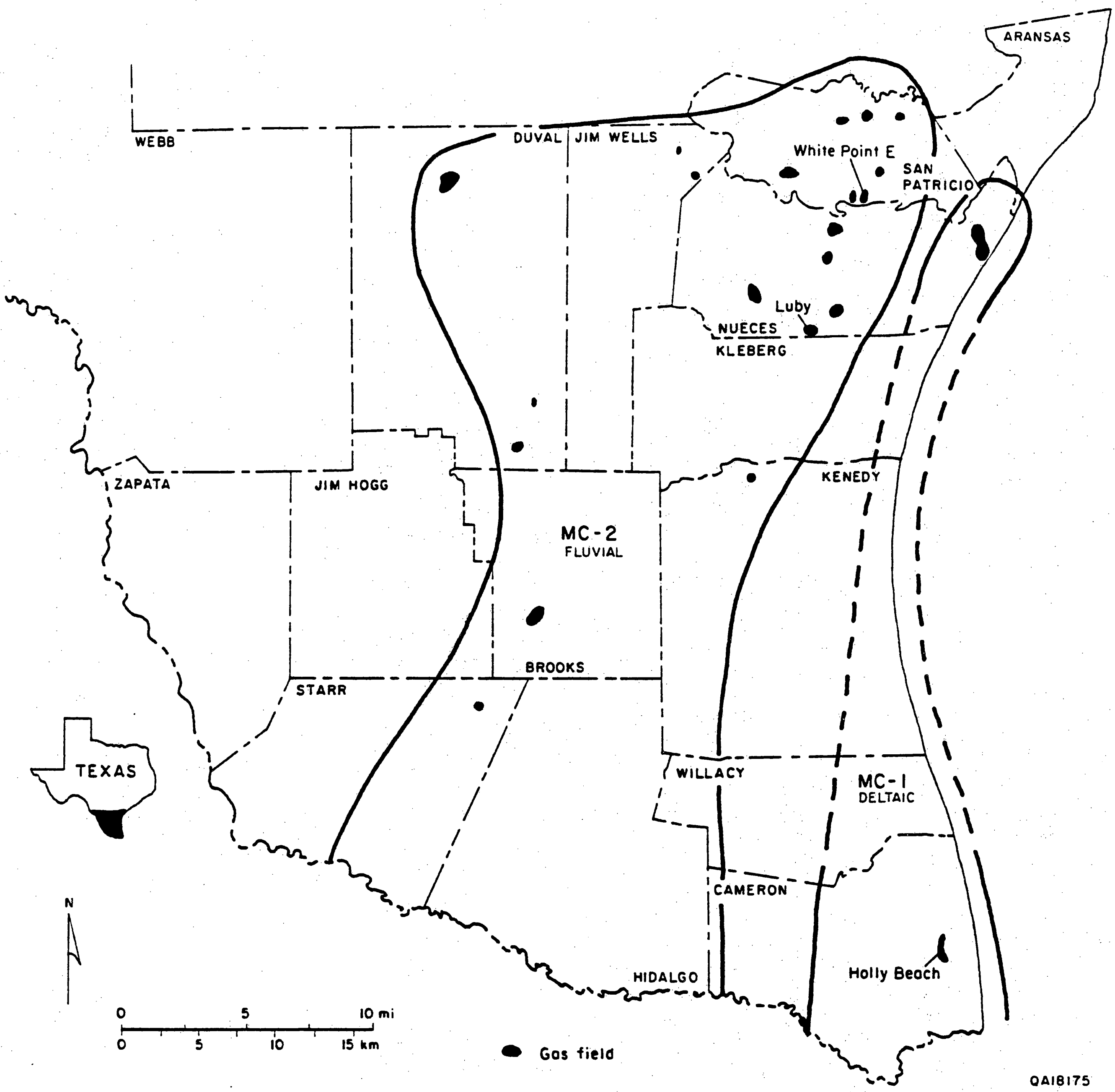

Figure 18. Miocene fields that contain nonassociated gas reservoir sections of all densities having PPY values >20 and REUR values between 0 and 3. Plays are from Kosters and others (1989) and based on depositional systems outlined by Galloway and others (1986). Field sizes and play boundaries are approximate.

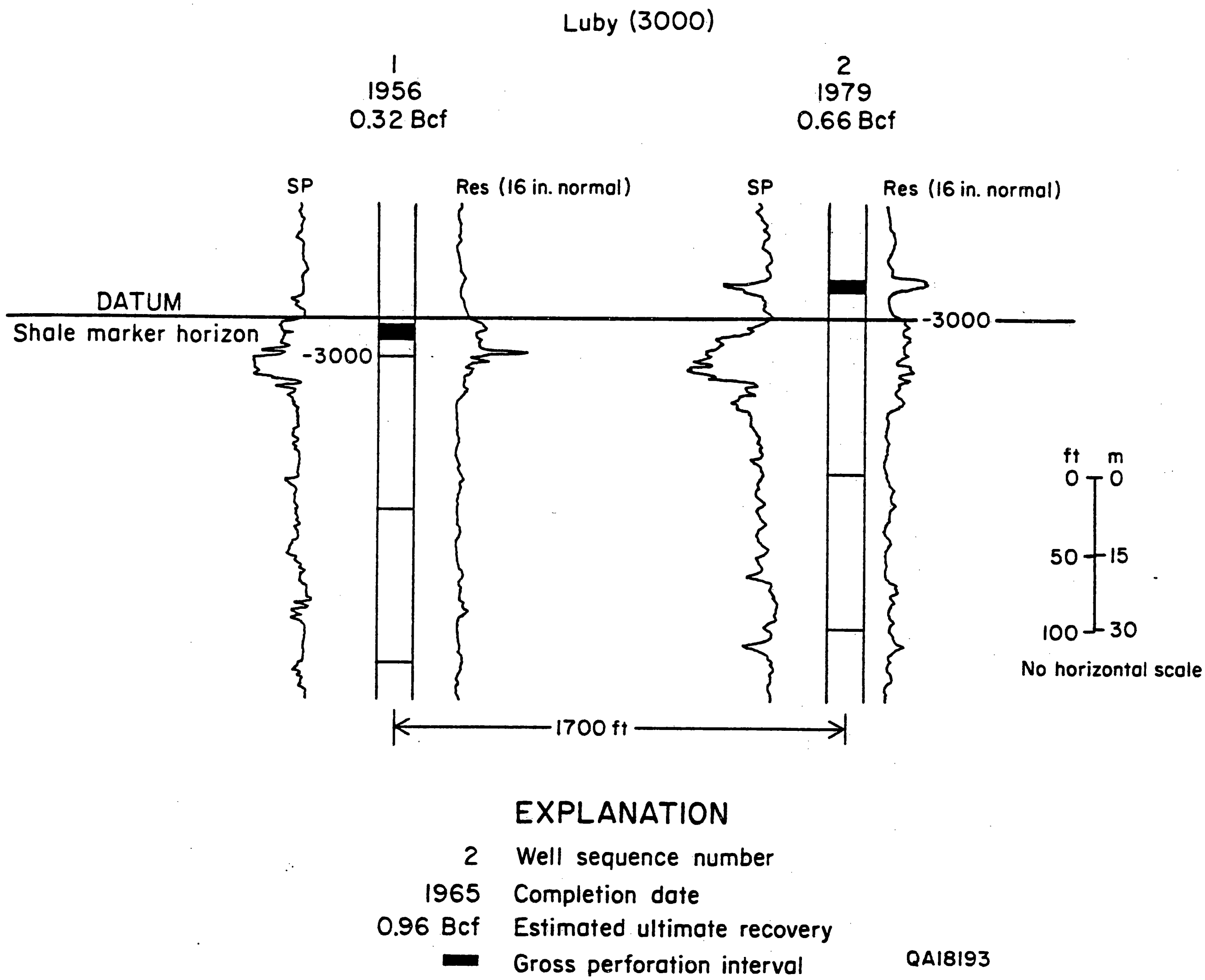

Figure 19. Reservoir section in Luby field, 3000 reservoir, showing perforations interpreted to be in fluvial sandstones. REUR of this section is 2.09. Field located in figure 18.

nearshore-marine sandstones (fig. 20). Porosity and permeability are high and water drives are common in this play as well (Kosters and others, 1989).

SELECTION OF STUDY UNITS

Analyses reported here were focused on those reservoir sections representing the highest reserve growth volumes as determined by the EEA infill analysis (Energy and Environmental Analysis, Inc., 1990, 1991). EEA divided all producing geologic units in district 4 into low-, medium-, and high-volume (or class) groups, analyzed the data for historical reserve growth, and, for each group, estimated and ranked the reserve growth potential. The highest class group within the Frio Formation represents 40 percent of the total EEA estimated reserve growth for district 4, and the Frio Formation as a whole contains 57 percent of the total estimated reserve growth. Reserve growth potential (including all classes) was estimated at 3 percent of the total district 4 estimate for the Vicksburg Formation, 20 percent for the Wilcox Group, and 6 percent for Miocene-age strata. No other units studied by EEA in the nonassociated gas reservoir infill analysis in district 4 contributed significantly to the EEA reserve growth estimate; thus, the Frio, Vicksburg, Wilcox, and Miocene geologic units were chosen for this analysis.

Terms used to describe reservoir-section characteristics are density (number of completions per section), PPY (prior production years of a reservoir section, representing the total number of well years of production before the last completion, or infill, was made), and REUR (recovery ratio, equal to the production of the infill completion being analyzed divided by the average of all previous completions in the reservoir section, representing the percentage of reserve growth). See appendix A for a more detailed explanation of these terms. Within each geologic unit chosen for study, detailed evaluation was made of reservoir sections representing the highest volumes of reserve growth, those with well densities from 2 to 4, PPY values >20, and REUR values in the top 50 percent (app. A). Reservoir sections with densities >4 were also analyzed in the Frio and Vicksburg Formations. Wilcox and Miocene data used by EEA in the nonassociated gas reservoir infill reserve growth analysis do not contain reservoir sections with densities >4. The Wilcox analysis included reservoir sections with PPY values >10 because of the small number of

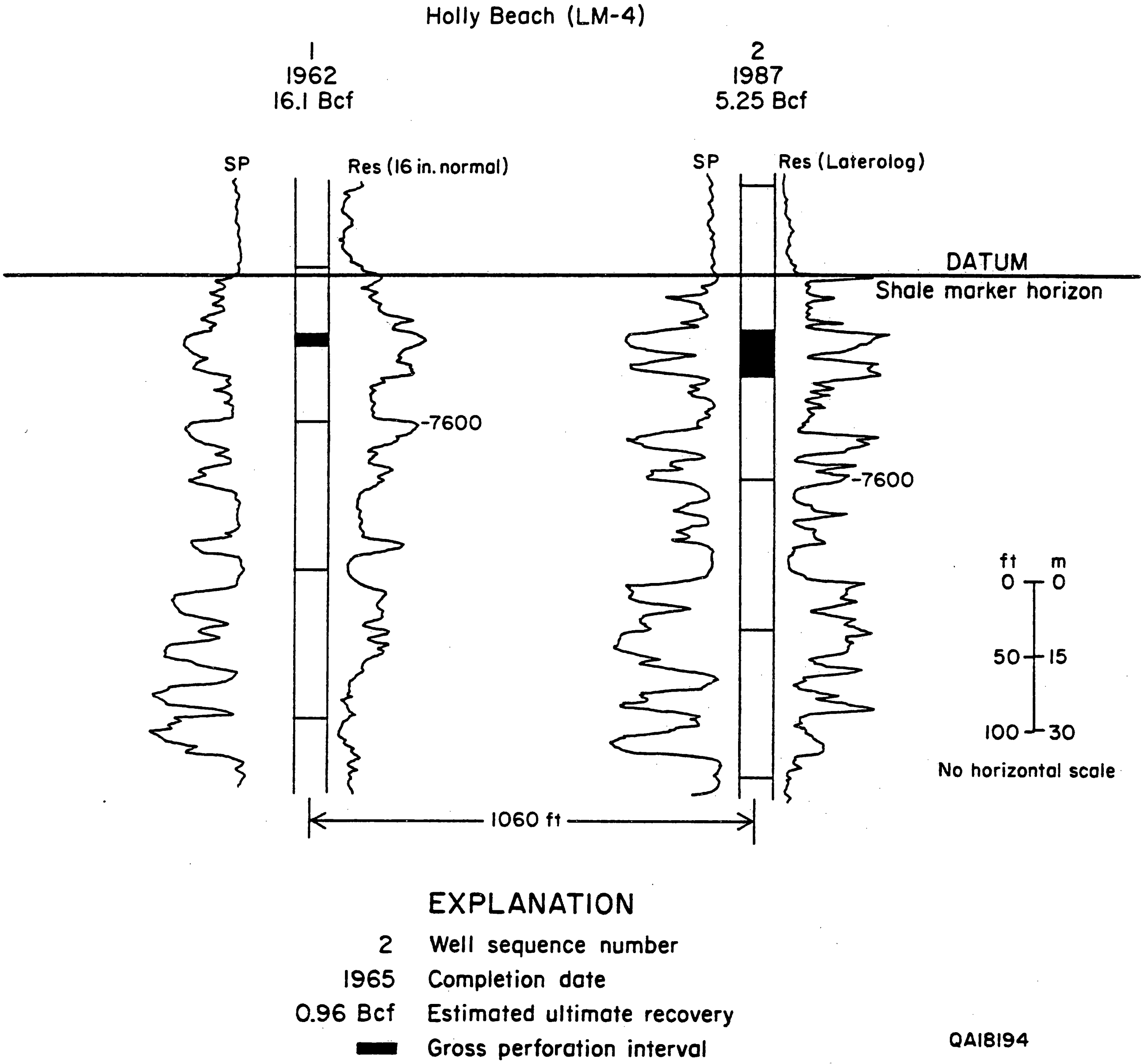

Figure 20. Reservoir section in Holly Beach field, LM-4 reservoir, showing within-reservoir perforations in deltaic sandstones. REUR of this section is 0.32. Field located in figure 18.

samples available with PPY values >20. Additionally, the Frio Formation analysis included reservoir sections with PPY values >10 and REUR values between 0 and 192.

RESERVOIR-SECTION TYPE ANALYSIS

Selected reservoir sections were analyzed for completion geometry (detailed placement of perforations) relative to sandstone-body geometry, drive mechanism, and production history in order to determine sections appropriate for use in reserve growth estimation in district 4. These reservoir-section characteristics were grouped into types for each geologic unit and are discussed in order of volumetric importance.

Frio Reservoir-Section Types

In the Frio Formation, seven types of reservoir sections were identified based on production characteristics and perforation geometries. Same-sandstone, overlapping, and different-sandstone completion types were determined from perforation geometries, the water-drive type was determined from production mechanism (documented by Railroad Commission of Texas hearings files and SP-log character), and cycled/injected, consolidated, and faulty data types were determined from production characteristics, completion dates, and well locations. Definitions and examples of the seven types follow.

1. *Same sandstone*, where completions in sandstone stringers are separated by 30 ft of shale or less. Completion geometries range from completions in laterally continuous sandstones of the same thickness (fig. 21) to sandstones of varying thickness (fig. 7), to splay, or stringer, sandstone geometries (fig. 22). Same-sandstone completion geometries are most abundant in sediments of fluvial and fluvial-deltaic origins. Field experience in the Secondary Gas Recovery project has shown that shale partings only a few feet thick may form effective reservoir barriers; a shale thickness of 30 ft was used in this study, however, in order to maintain a conservative approach.

2. *Overlapping*, where some completions are in the principal target sandstone and some tap one or more separate sandstones that may or may not be in addition to a completion in the target sandstone. The distinguishing characteristic of this type of completion geometry is that some part of each sandstone

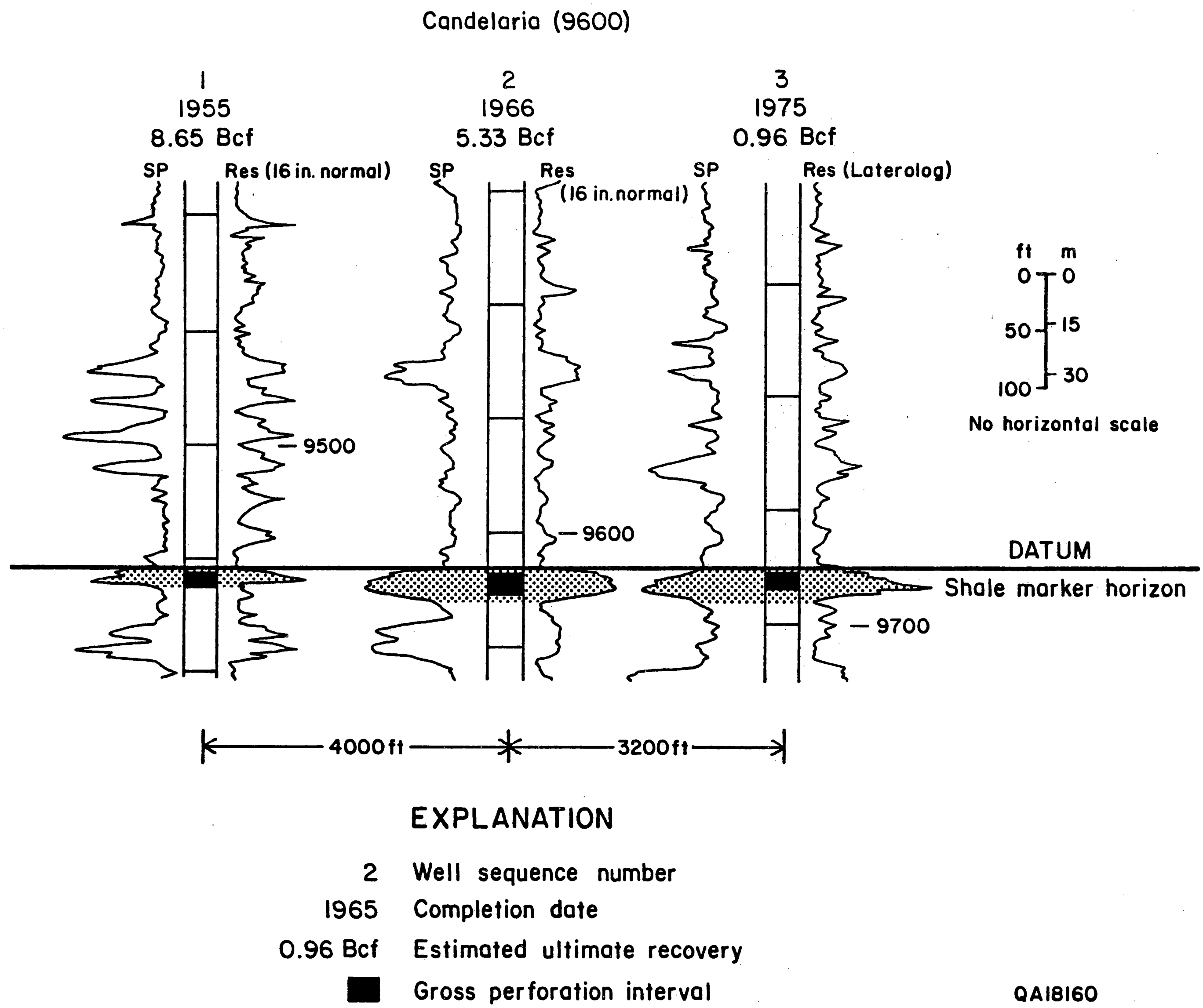

Figure 21. Reservoir section in Candelaria field, 9600 reservoir, showing same-sandstone completions in a laterally continuous sandstone with relatively consistent thickness. REUR of this section is 0.13. Field located in figure 5.

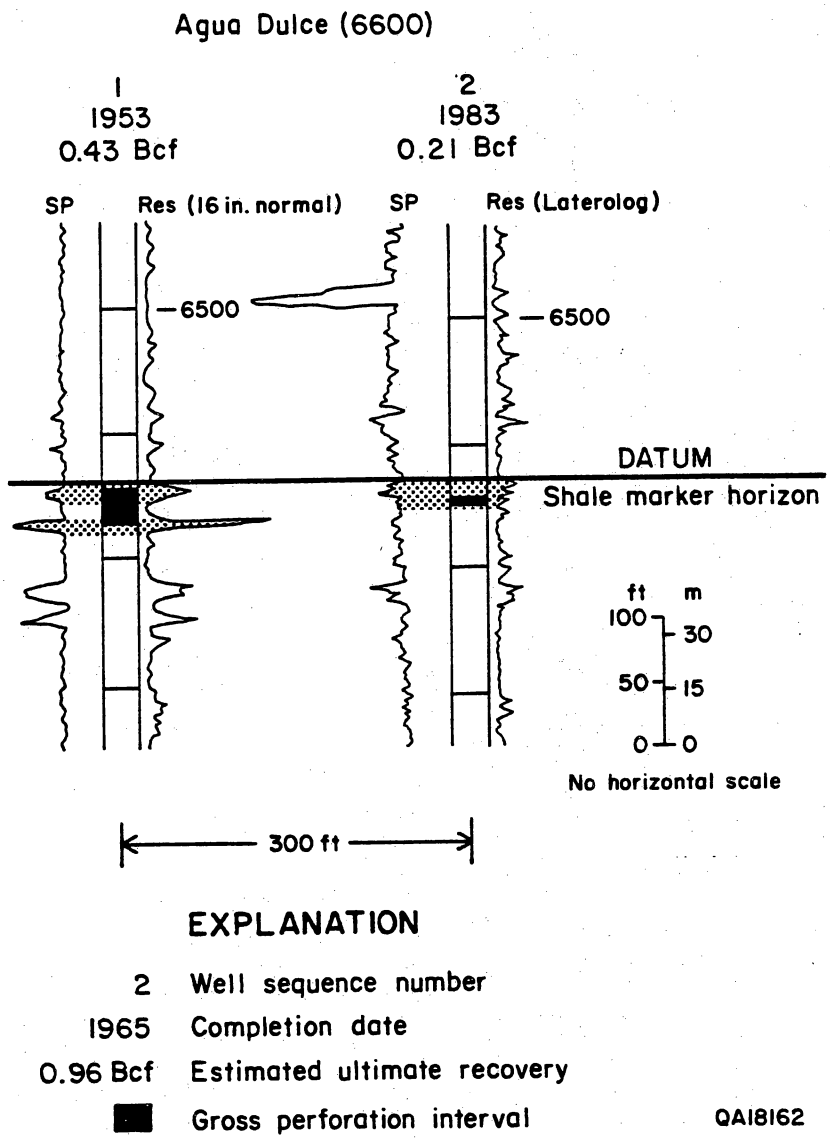

Figure 22. Reservoir section in Agua Dulce field, 6600 reservoir, showing same-sandstone completions in stringer, or splay, geometry. REUR of this section is 0.48. Field located in figure 5.

interval completed is also completed in another well in the section. Overlapping completion geometries occur in both fluvial (fig. 9) and deltaic sections (fig. 23).

In fluvial sections, overlapping completions in a large reservoir may tap laterally discontinuous sandstones (10 to 20 ft thick) that lie above or below the thicker, laterally continuous reservoir unit. Early development practice indicates that these stray, or stringer, sandstones were considered to be part of the main reservoir as a single, relatively homogeneous zone. In deltaic sandstones, low-permeability reservoirs may be defined as zones up to 400 ft thick that contain several discrete sandstone units. Not all of these units are perforated in all of the wells, suggesting that more detailed correlation of upward-coarsening cycles may yield reserve growth targets.

3. *Different sandstone*, where completions in sandstones are separated by more than 30 ft of shale. Completion geometries range from completions in fluvial channel and splay sandstones (fig. 24) and deltaic sandstones (fig. 25) to barrier/strandplain sandstones (fig. 26). Different-sandstone completions are most abundant in reservoir sections containing sediments of deltaic origin, corresponding to a gulfward increase in stratigraphic and structural complexity (figs. 27 and 28).

Many different-sandstone reservoir sections contain a well or wells that were completed in the 1940's. As geological tools and engineering tests improved over time, operators were able to better define reservoir limits and the boundaries of these early reservoirs were often changed in later years, resulting in different-sandstone completion geometries. Current regulations require that sandstones separated by ≥50 ft of shale be listed as separate reservoirs; however, many exceptions to this practice appear in completions made prior to 1980.

4. *Water-drive* reservoirs, where thick, permeable sandstone units allow aquifer flow to maintain pressure in a gas reservoir (fig. 8). Thick sandstones containing aquifers are most common in reservoir sections in downdip barrier island and deltaic deposits. Infill drilling in these highly permeable reservoirs is primarily structurally controlled, with operators perforating new completions updip in each reservoir as structurally lower wells water out.

5. *Cycled/injected* reservoirs, where gas withdrawn from the reservoir is reinjected into the same reservoir (fig. 10). The purpose of gas cycling is to allow optimal production of condensate. Many

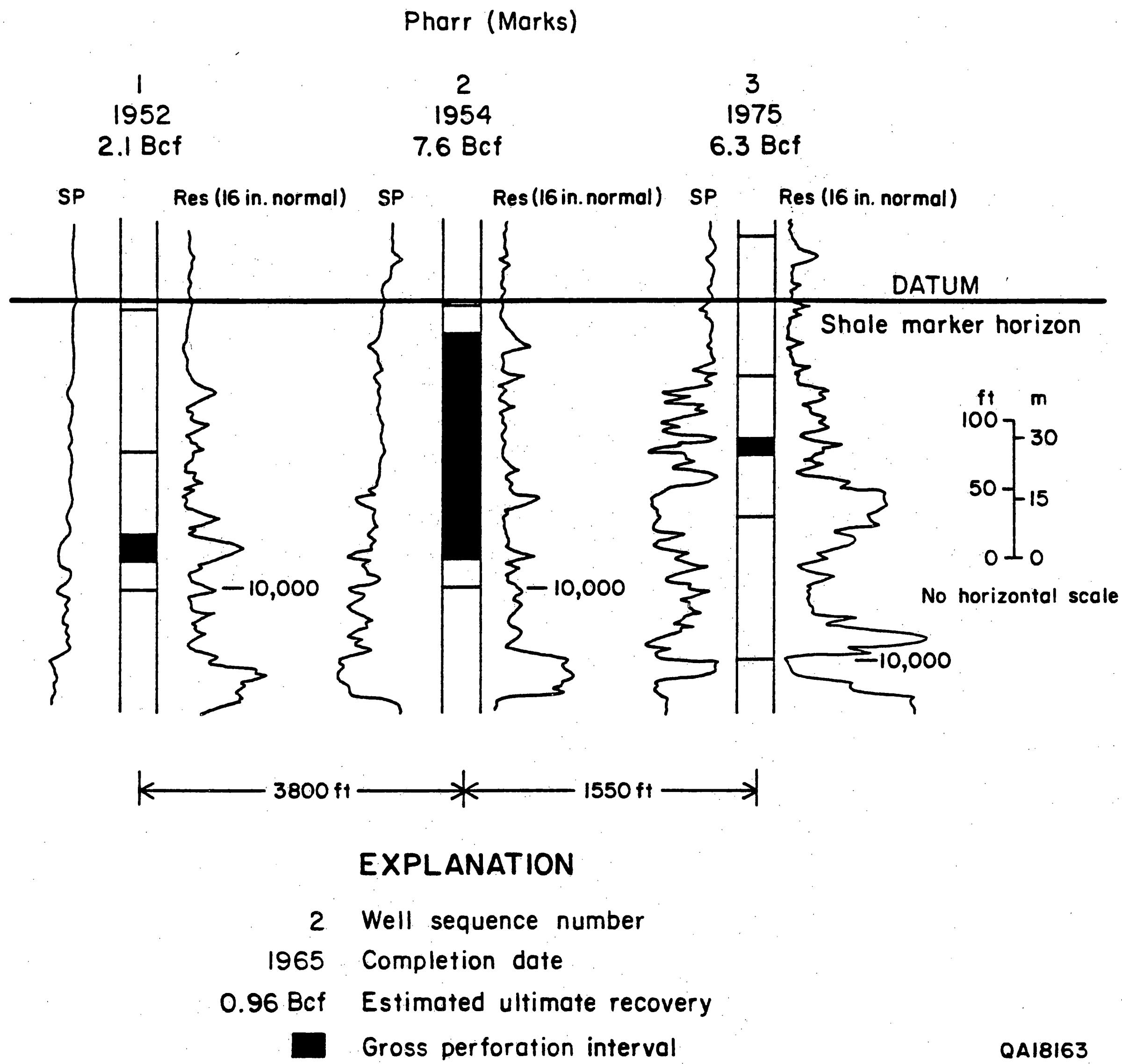

Figure 23. Reservoir section in Pharr field, Marks reservoir, showing overlapping sandstone completions interpreted to be in a delta-front depositional environment. REUR of this section is 1.30. Section may be affected by growth faulting. Field located in figure 5.

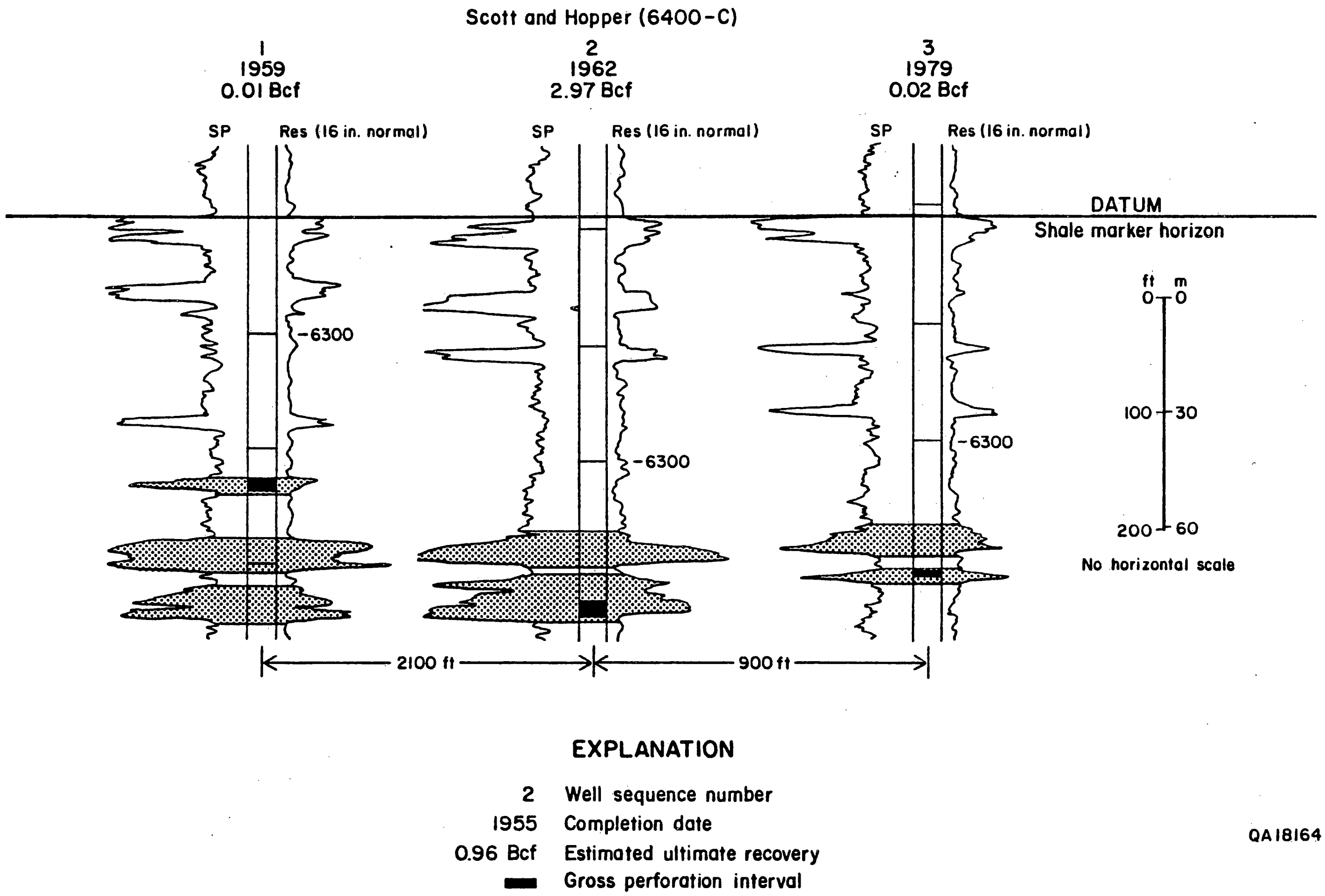

Figure 24. Reservoir section in Scott & Hopper field, 6400-C reservoir, showing different-sandstone completions in a fluvial setting. Relatively thin sandstones with spiky S.P.-log character are interpreted as channel and splay deposits. REUR of this section is 0.01. Field located in figure 5.

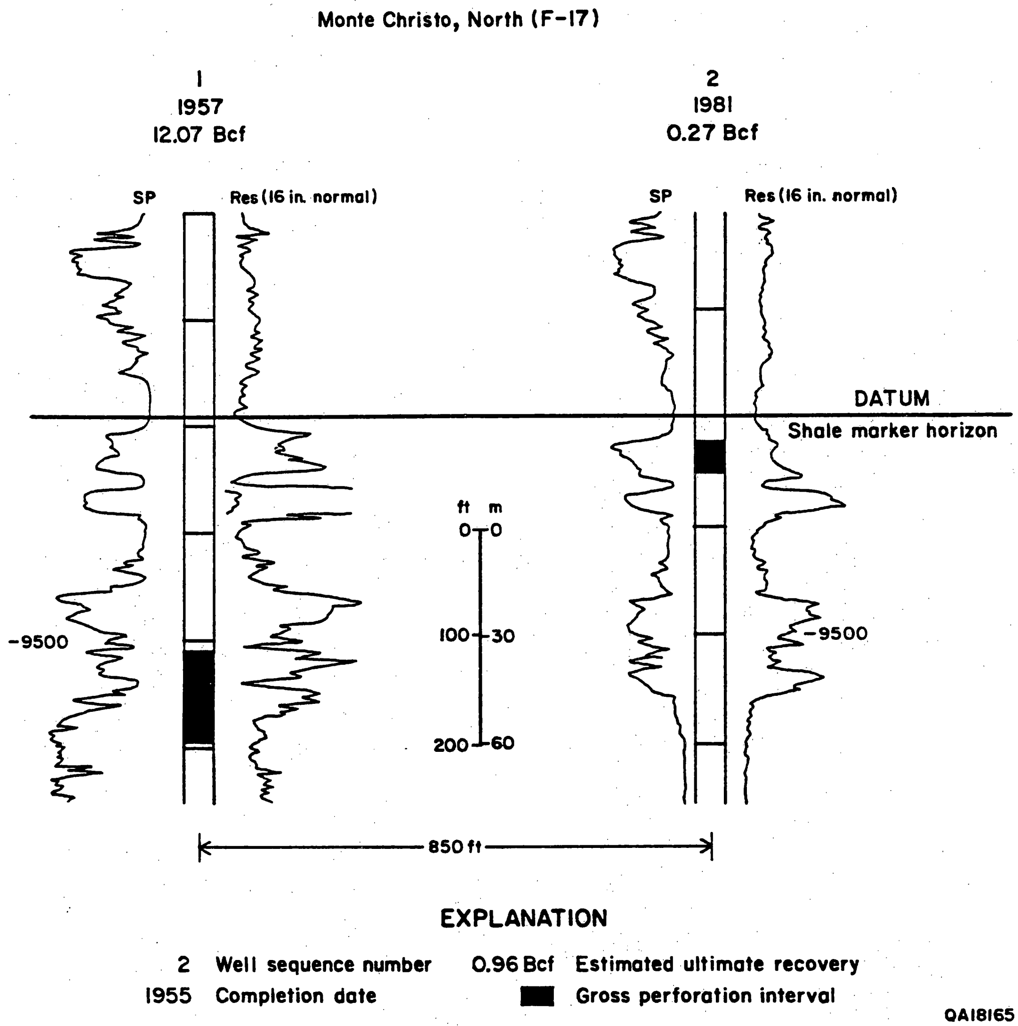

Figure 25. Reservoir section in Monte Christo, North field, F-17 reservoir, showing different-sandstone completions in a deltaic setting. Thick, coarsening-upward sandstones are interpreted as delta-front and delta-distributary sandstones. REUR of this section is 0.02. Field located in figure 5.

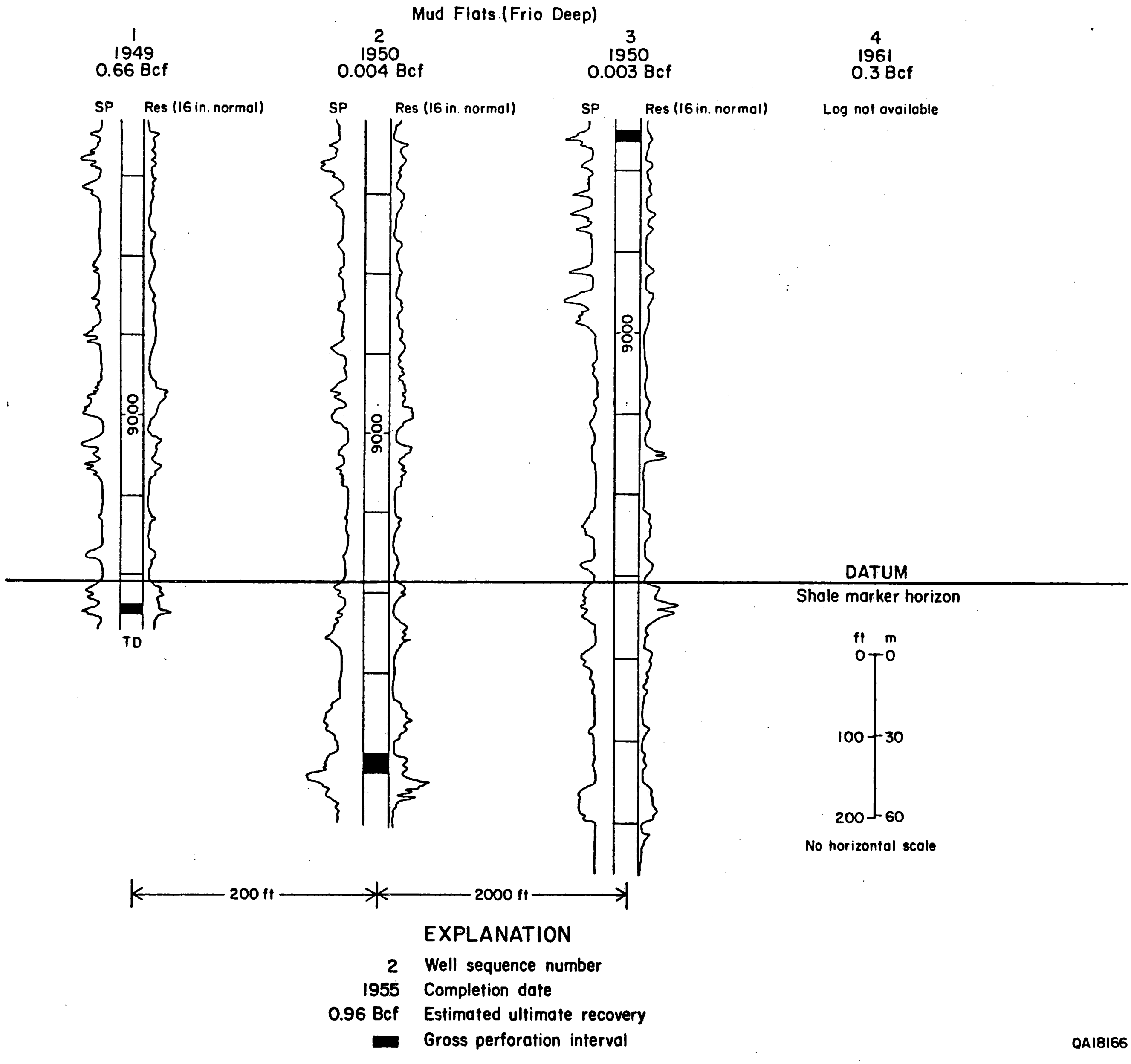

Figure 26. Reservoir section in Mud Flats field, Frio Deep reservoir, showing different sandstone completions interpreted to be in a strandplain depositional environment. REUR of this section is 1.37. Field located in figure 5.

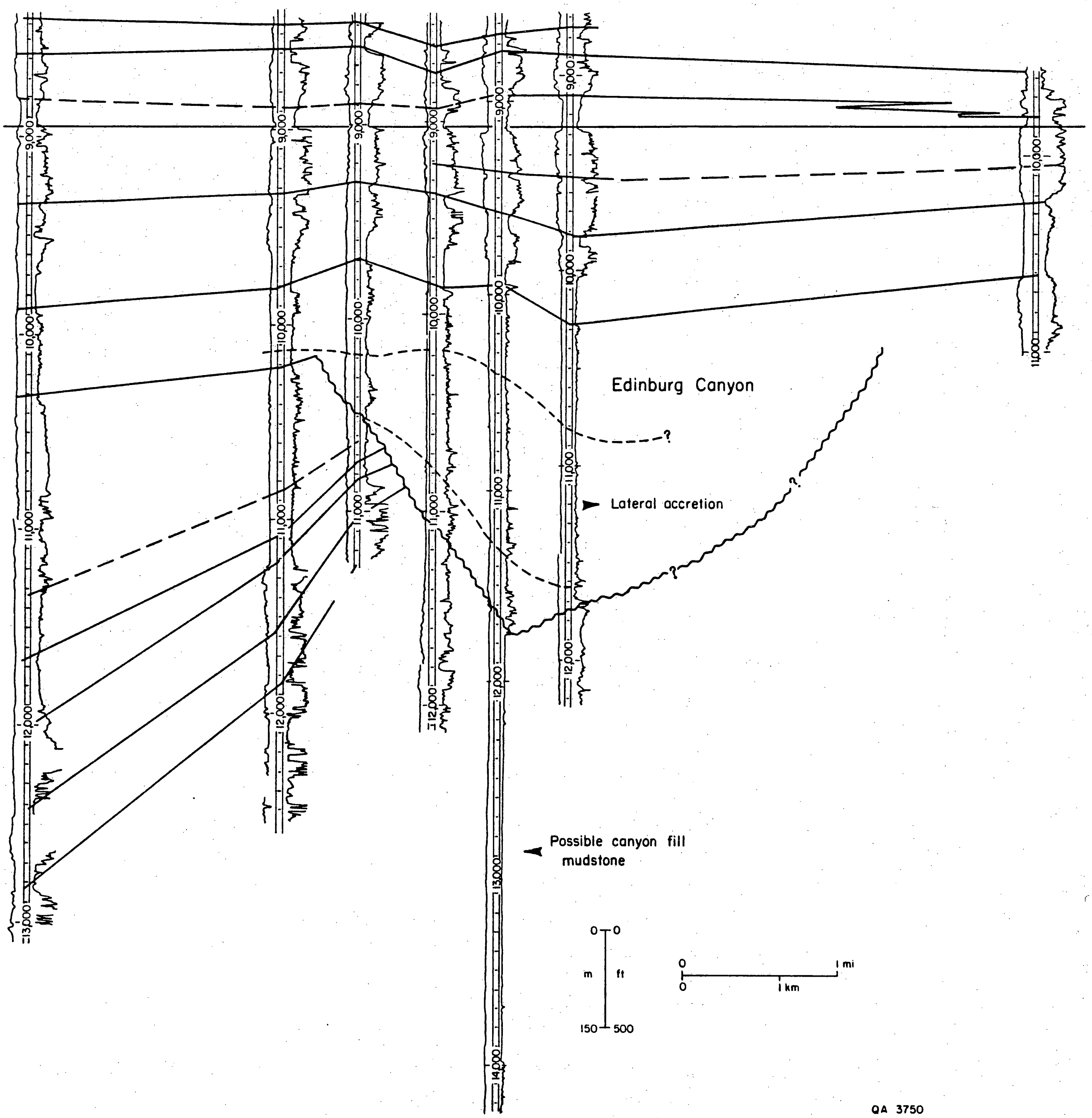

Figure 27. Stratigraphic complexity in a strike-oriented cross section in Edinburg field, Hidalgo County, showing a high-relief unconformity interpreted as a mud-dominated submarine-canyon system incised into lower Frio shoreline and coastal barrier sandstones. Sandstones occur at similar depths on either side of the unconformity, suggesting that correct stratigraphic correlation in this area requires data in addition to geophysical logs, and that early reservoir development would be prone to different-sandstone completions. From Galloway (1985).

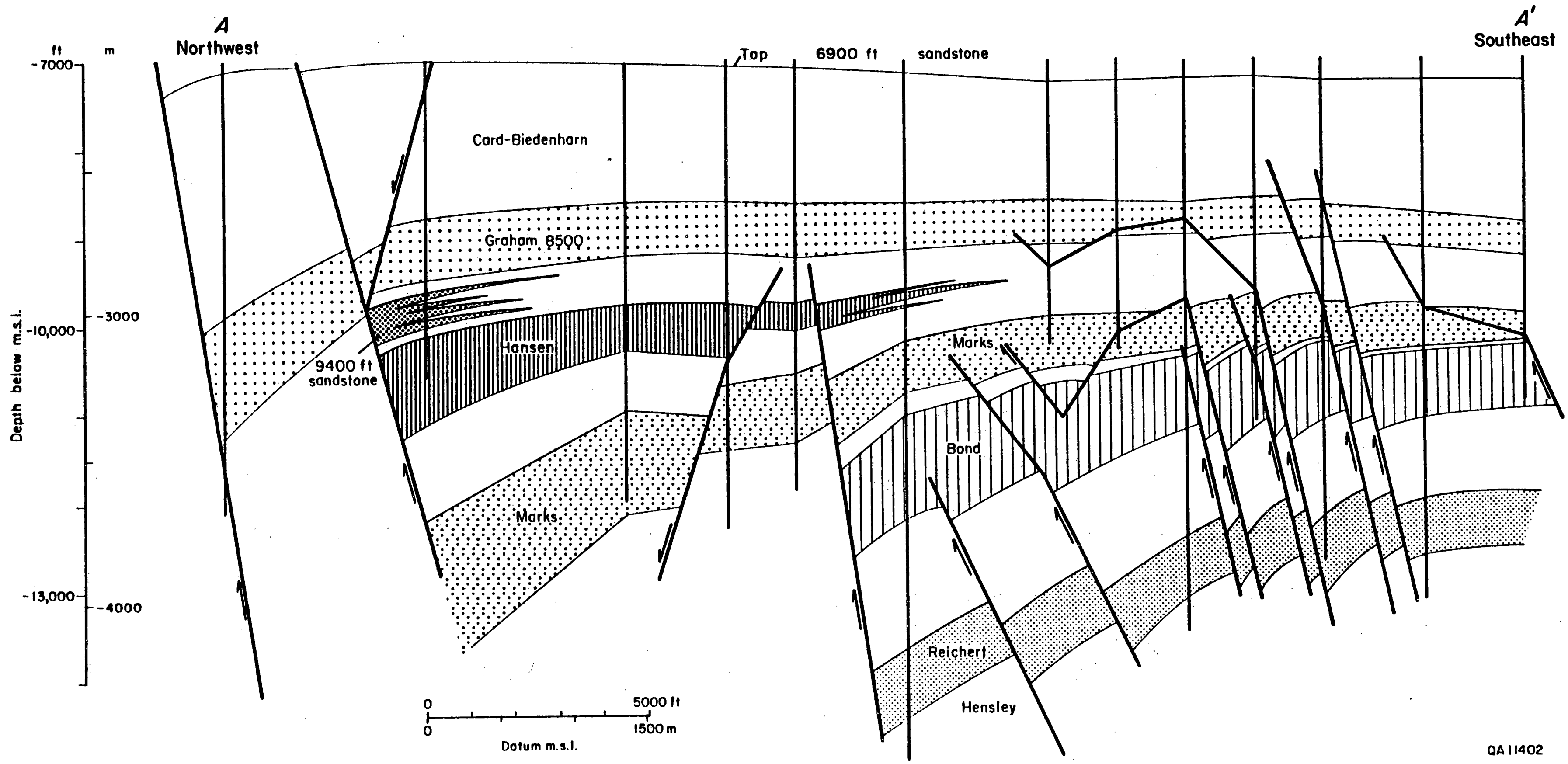

Figure 28. Structural complexity in a dip-oriented stratigraphic cross section in McAllen field, Hidalgo County, showing a relatively unfaulted rollover anticline to the northwest and deeper, densely faulted reservoirs to the southeast. Modified from Collins (1983).

volumetrically large Frio nonassociated gas reservoirs were discovered in the 1930's and 1940's when there was a limited market for gas, and pipeline systems were not extensive. Condensate was sold from these reservoirs until the gas market improved. Pre-1966 cycling records are not easily obtained in the public domain but may be available from operators on a reservoir basis (table 1).

A few Frio gas reservoirs in the EEA analysis were identified as having been injected with gas. These reservoirs (or portions of them) apparently had an oil rim but are now classified as nonassociated gas reservoirs. The volume of injected gas identified in the EEA analysis is limited to these types of reservoirs and does not appear to properly compensate for gas cycling in district 4 (table 1).

6. *Consolidated* reservoirs, where two or more single reservoirs are coproduced from the same well (fig. 29). Consolidation allows production from reservoirs that are below the limit of economic production to be combined with other reservoirs to attain workable pipeline pressures. This can be accomplished as long as reservoir cross flow is not a problem.

7. Reservoir sections with *faulty data* (explanation follows).

Each Frio *reservoir-section type* has implications for use in reserve growth estimation:

1. *Same sandstone*—Reserve growth from same-sandstone completions is considered to represent within-reservoir reserve growth when infill well production is from partially or totally untapped compartments in a reservoir (fig. 30). Pressure analyses of selected reservoir sections were used to determine the extent of well connectivity and the amount of additional gas production (app. B).

2. *Overlapping*—Reserve growth from Frio overlapping completions is considered valid in the same respect as reserve growth from same-sandstone completions.

3. *Different sandstone*—Reserve growth from different-sandstone completions is demonstrated by the reservoir-section examples in this type. Different-sandstone reserve growth does not represent within-reservoir reserve growth as defined in this study. The EEA analysis separated reserve growth estimates for infill drilling, assumed to be within-reservoir, from reserve growth estimates for extension drilling, assumed to be extrareservoir (different-sandstone). The use of REUR values from the different-sandstone completions identified in the EEA infill analysis to predict within-reservoir reserve growth is not geologically appropriate.

Table 1. Injected volumes from 9 of the 36 cycled Frio and Vicksburg reservoirs that contain EEA reservoir sections. These data suggest that the nonassociated injected gas volume of 909 Bcf used in the EEA analysis for district 4 is too low. A total of 64 cycled reservoir sections were identified in this analysis (apps. C and D).

Field (Reservoir)	Injected gas (Bcf)
La Gloria (Bauman North)	11.016
La Gloria (Bauman South)	76.357
La Gloria (Brooks and Culpepper)	318.484
La Gloria (Jim Wells)	190.811
La Gloria (Los Olmos)	17.282
La Gloria (Maun Stray)	37.401
La Gloria (Riley)	7.985
La Gloria (Scott)	147.553
La Gloria (Stolze)	17.894
Total	824.783

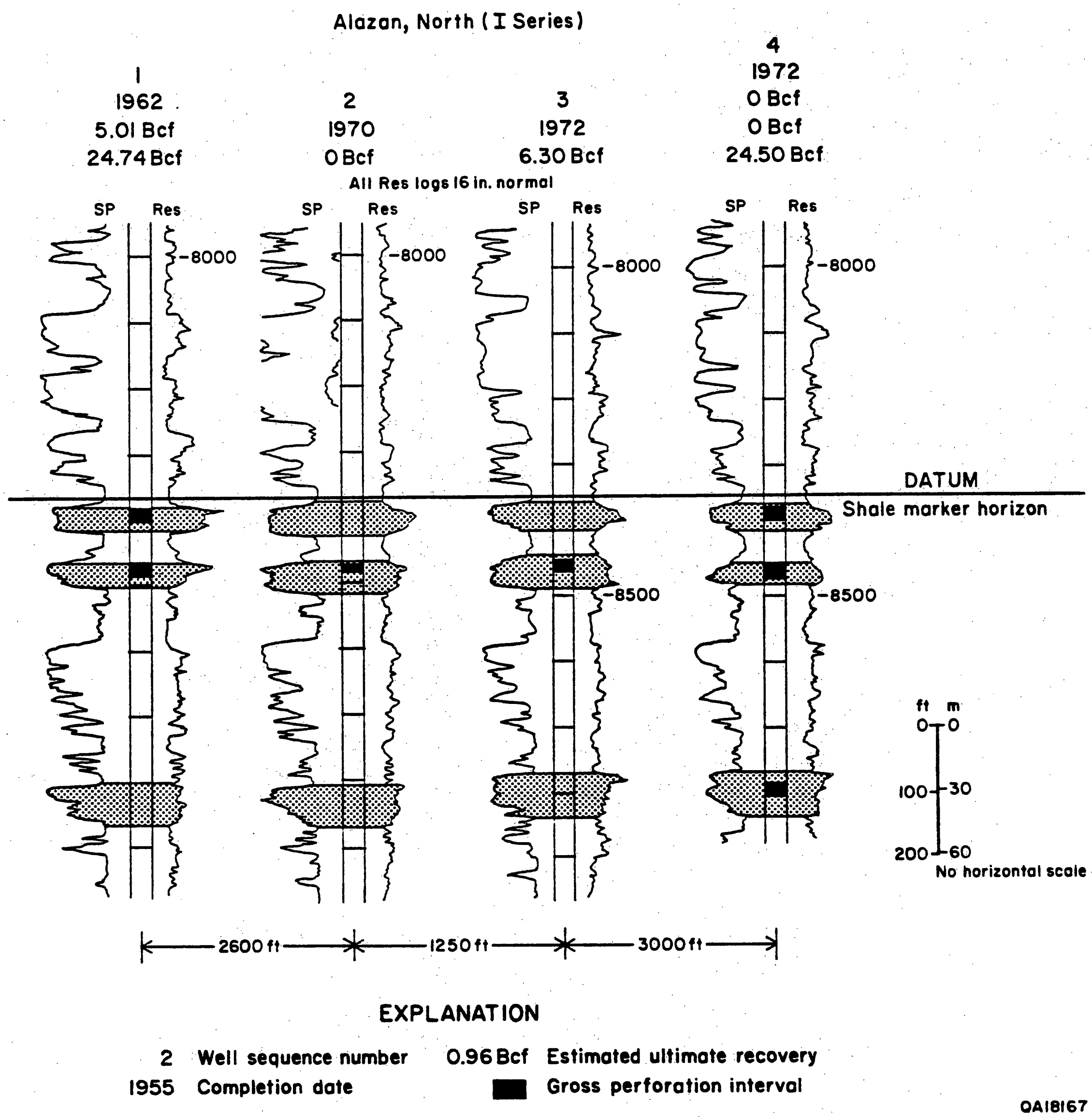

Figure 29. Reservoir section in Alazan, North field, I Series reservoir, showing the distribution of completions in a consolidated reservoir. REUR of this section is 0.35. Field located in figure 5.

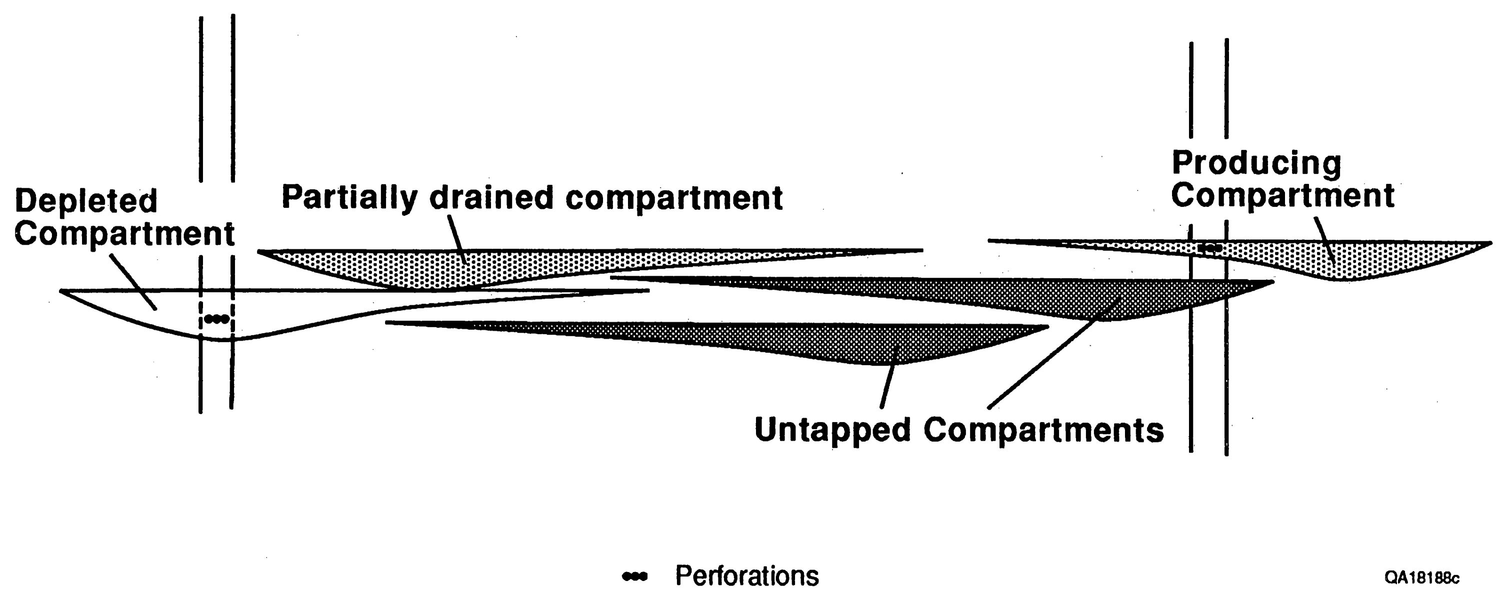

Figure 30. Schematic reservoir and completion configuration in fluvial sediments showing partially drained and untapped targets for infill drilling. Expected pressure encountered by an infill completion in partially drained compartments would be higher than existing average reservoir pressure but lower than virgin reservoir pressure. Expected pressure encountered by an infill completion in untapped compartments would be virgin pressure appropriate to the depth and temperature of the rock. Adapted from Levey and others (1992).

4. *Water drive*—Water-drive reservoirs occur predominantly in highly permeable, thick (>100 ft) sandstones. Pressure analysis (fig. 31) indicates that water-drive infill completion pressures are approximately equal to existing average reservoir pressure, suggesting that the completions are in communication. In contrast to depletion-drive reservoirs, where optimal infill wells are perforated in partially or totally isolated compartments, infill wells in water-drive reservoirs are often drilled structurally higher as deeper wells water out. Because reserve growth from water-drive reservoirs is governed by different processes than is reserve growth from pressure depletion-drive reservoirs (which are the dominant type in Frio district 4 reservoirs), it may be inappropriate to use REUR values from water-drive reservoir sections for prediction of reserve growth in depletion-drive reservoirs, especially when pressure data suggest continuity of reservoir units. Reserve growth through coproduction of gas and water was omitted as a reserve growth mechanism in this study.

5. *Cycled/injected*—Production volumes from completions in cycled and gas-injected reservoirs include injected gas volumes. To obtain a valid recovery ratio (REUR) in these reservoirs, net gas production should be used instead of gross gas production. Although a district-wide correction for gas injection was made in the EEA analysis, the adjustment appears to undercompensate for cycled volumes (table 1). Net gas production on a by-well basis is unavailable for cycled reservoirs in district 4.

REUR values in cycled reservoir sections are inappropriate for prediction of reserve growth based on standard engineering practices. The problem is compounded if reserve growth is predicted using one-well sections in cycled reservoirs.

6. *Consolidated*—Completion geometries in consolidated reservoirs are similar to those from different-sandstone reservoirs. REUR values from consolidated reservoirs are unsuitable for geologically based, within-reservoir prediction of reserve growth.

7. *Faulty data*—Frio reservoir sections with faulty data include sections where (1) the first production date differs from the date of completion (PPY should be smaller), (2) two different wells are reported with the same API number and their production is combined (REUR should be larger), (3) one or more completions have no production (REUR should be smaller), (4) the reservoir is not in production decline when the last (youngest) well is drilled, and (5) well locations are >5,280 ft apart. REUR values from these

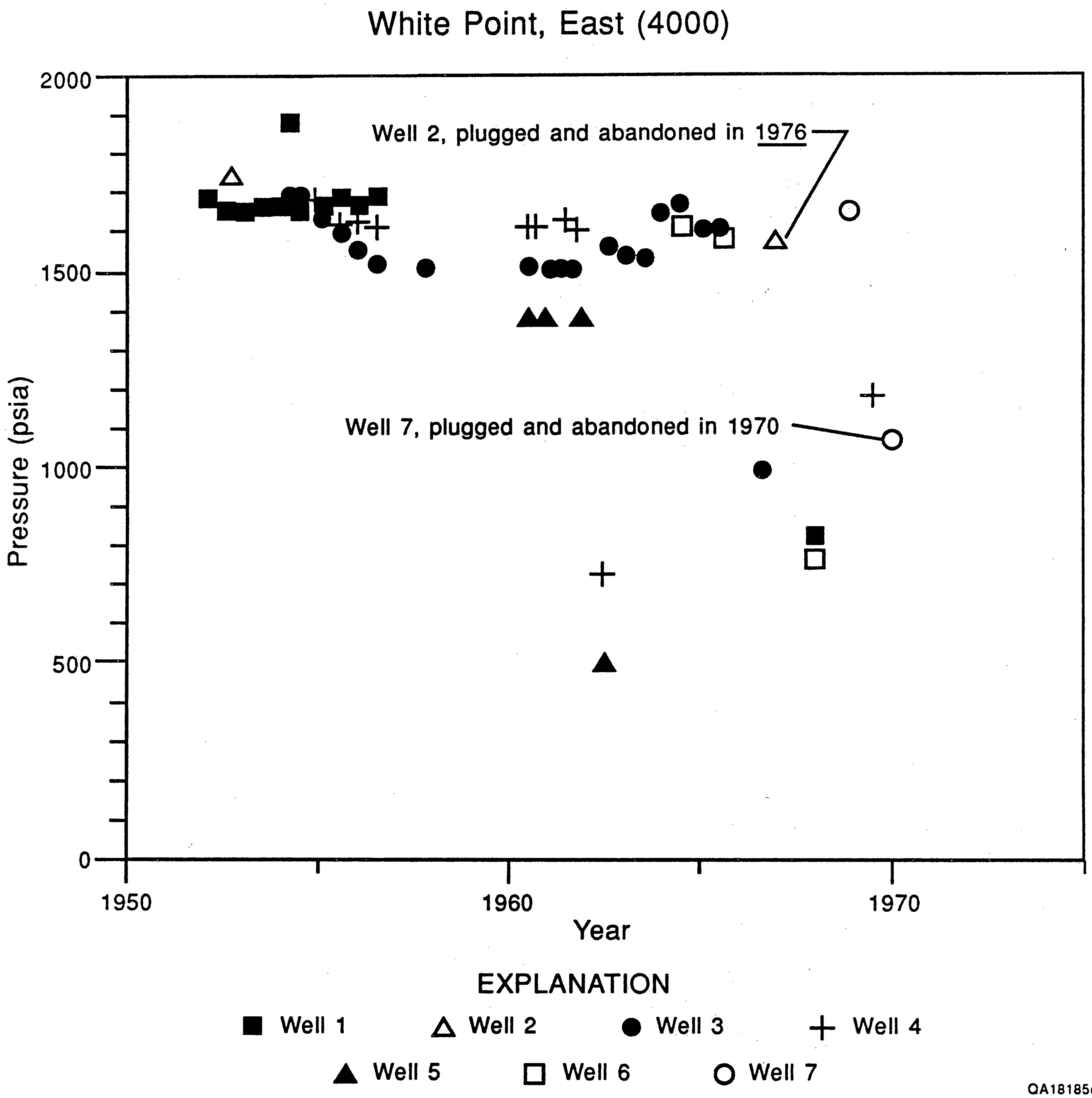

Figure 31. Pressure analysis from the White Point, East field, 4000 reservoir, showing the stable nature of reservoir pressure (1650 psi) within a 7-completion reservoir section in this water drive reservoir. As each well became depleted its pressure dropped rapidly while that of the remaining wells remained relatively high. Note that the seventh completion in the reservoir section, completed in 1968, was plugged and abandoned in 1970 while the second completion in the section, completed in 1952, produced six additional years (until 1976). This type of production history shows an important difference between water-drive and same-sandstone depletion-drive reservoirs, where initial wells are often depleted when infill completions are made. Location of White Point, East field is shown in figure 5, and completion geometry is shown in figure 8.

reservoir sections are not mathematically compatible with the methods used in this study for reserve growth prediction.

Of the seven types of Frio reservoir sections, same-sandstone reservoir sections where infill completions contact incremental gas volumes are considered the most sound estimator of geologically based within-reservoir reserve growth in district 4 Frio reservoirs. These represent 18 to 30 percent of the reservoir sections used to predict nonassociated gas reservoir reserve growth in the EEA analysis for Frio reservoir sections with PPY values >20, densities from 2 to 4, and REUR values between 0 and 3 (tables 2 and 3, app. C). In addition, 8 to 24 percent of Frio reservoir sections with densities >4 were estimated to appropriately represent reserve growth and 23 percent to 38 percent of the reservoir sections with PPY values from 10 to 20 and REUR values from 0 to 3. Some implications of these results are summarized in the Discussion and Conclusions section of this report.

Vicksburg Reservoir-Section Types

In the Vicksburg Formation, reservoir sections were located in sediments that are predominantly deltaic in origin. Reservoir-section types identified included same-, overlapping, and different-sandstone perforation geometries in addition to water-drive, cycled/injected, consolidated, and faulty data types. Vicksburg reservoir-section types are similar to Frio types and are briefly described as follows:

1. *Same sandstone*, where completions in sandstone stringers are separated by ≤30 ft of shale (fig. 13). Few same-sandstone completion geometries were identified in Vicksburg reservoir sections.

2. *Overlapping*, where some completions are in the target sandstone and some tap one or more separate sandstones. Overlapping completion geometries are abundant in Vicksburg reservoir sections (figs. 14, 32, and 33). In contrast to a completion in a higher permeability, shallower fluvial Frio sandstone, a completion in a single, low-permeability (0.05 md) Vicksburg deltaic unit often will not pay for the drilling and operational costs of a well. For Vicksburg wells to be profitable, completions are made across long, hydraulically fractured intervals that may incorporate two or more discrete reservoir sandstones (fig. 34). Newly recognized depositional and diagenetic heterogeneities in these stratigraphically and structurally

Table 2. Summary of reservoir-section types identified in Frio reservoir sections with well densities from 2 to 4, PPY values >10, and REUR values between 0 and 3. Reservoir sections with PPY values >20 and REUR values in the top 50 percent are designated as >20 top half, and reservoir sections with PPY values >20 and REUR values in the bottom 50 percent are designated as >20 bottom half. For calculation of percentage of reservoir sections estimated to represent geometrically and barically valid reserve growth, see table 3.

	Reservoir-section type	Number of sections	
All reservoir sections in the >20 top half, densities 2–4			
	Consolidated	1	
	Cycled	25	
	Different, overlapping, same, and water drive	49	
	Faulty data	10	
	Examined[1]	16	
	Not examined	19	
	Total	120	
Subset of reservoir sections in the >20 top half, densities 2–4			
	Different sandstone	14	
	Overlapping	2	
	Same sandstone	30	
	Water drive	3	
	Total	49	
Percentage of reservoir sections in the >20 top half, densities 2–4 group estimated to represent geometrically and barically valid reserve growth			18 to 30%
	Reservoir-section type	Number of sections	
All reservoir sections in the >20 top half, densities >4			
	Consolidated	3	
	Cycled	8	
	Different, overlapping, same, and water drive	10	
	Faulty data	1	
	Examined	9	
	Not examined	5	
	Total	36	
Subset of reservoir sections in the >20 top half, densities >4			
	Different sandstone	4	
	Overlapping	2	
	Same sandstone	3	
	Water drive	1	
	Total	10	
Percentage of reservoir sections in the >20 top half, densities >4 group estimated to represent geometrically and barically valid reserve growth			14 to 24%
	Reservoir-section type	Number of sections	
All reservoir sections in the >20 bottom half, densities 2–4			
	Consolidated	3	
	Cycled	15	
	Different, overlapping, same, and water drive	38	
	Faulty data	2	

[1] Section partially complete—some well logs examined but type not determined

	Examined	13	
	Not examined	24	
	Total	95	
Subset of reservoir sections in the >20 bottom half, densities 2–4			
	Different sandstone	14	
	Overlapping	1	
	Same sandstone	22	
	Water drive	1	
	Total	38	
Percentage of reservoir sections in the >20 bottom half, densities 2–4 group estimated to represent geometrically and barically valid reserve growth			18 to 30%
	Reservoir-section type	Number of sections	
All reservoir sections in the >20 bottom half, densities >4			
	Consolidated	4	
	Cycled	5	
	Different, overlapping, same, and water drive	11	
	Faulty data	1	
	Examined	6	
	Not examined	1	
	Total	28	
Subset of reservoir sections in the >20 bottom half, densities >4			
	Different sandstone	1	
	Overlapping	2	
	Same sandstone	6	
	Water drive	2	
	Total	28	
Percentage of reservoir sections in the >20 bottom half, densities >4 group estimated to represent geometrically and barically valid reserve growth			8 to 14%
	Reservoir-section type	Number of sections	
All reservoir sections with 10–20 PPY, densities 2–4			
	Consolidated	3	
	Cycled	19	
	Different, overlapping, same, and water drive	29	
	Faulty data	4	
	Examined	5	
	Not examined	170	
	Total	230	
Subset of reservoir sections with 10–20 PPY, densities 2–4			
	Different sandstone	8	
	Overlapping	2	
	Same sandstone	16	
	Water drive	3	
	Total	29	
Percentage of reservoir sections with 10–20 PPY, densities 2–4 group estimated to represent geometrically and barically valid reserve growth			23 to 38%
	Reservoir-section type	Number of sections	
All reservoir sections with 10–20 PPY, densities >4			
	Consolidated	2	
	Cycled	0	

Table 2 (cont.)

	Different, overlapping, same, and water drive	2	
	Faulty data	1	
	Examined	2	
	Not examined	5	
	Total	12	
Subset of reservoir sections with 10–20 PPY, densities >4			
	Different sandstone	2	
	Overlapping	0	
	Same sandstone	0	
	Water drive	0	
	Total	2	
Percentage of reservoir sections with 10–20 PPY, densities >4 group estimated to represent geometrically and barically valid reserve growth			insufficient data

Table 3. Estimate of reservoir sections that represent within-reservoir reserve growth in the total Frio reservoir-section group with PPY values >20, well densities from 2-4, and REUR values in the top 50 percent (designated as the >20 top half). The estimate was made in three steps:

Step 1. The percentage of reservoir sections **not** considered valid as examples of reserve growth, composed of the consolidated, cycled, and faulty data reservoir sections (30 percent, from part A below) was subtracted from the total percentage of reservoir sections, resulting in a remaining group of sections considered to be valid in terms of gas volumes produced and years producing.

Step 2. The "remaining" sections (70 percent in part B below) are composed of both classified (different-sandstone, same-sandstone, water drive, and overlapping) and unclassified (examined and not examined) reservoir sections. The unclassified group of reservoir sections was considered to have the same percentage distribution of reservoir-section types as the classified group, so a calculation to find the percentage distribution in the total was unnecessary at this stage. However, different-sandstone reservoir sections were **not** considered to represent within-reservoir reserve growth, so these were removed from the total estimate by multiplying the percentage of different-sandstone reservoir sections in the classified group (29 percent in part A below) by the total for the remaining group and then subtracting this value (20 percent in part B below) from the remaining group. Step 2 therefore estimates the percentage of reservoir sections in the Frio >20 top-half group that are considered to be geometrically valid[1] (50 percent in part B, next page).

Step 3. The percentage of same-sandstone reservoir sections that represent definite and possible reserve growth in the pressure analyses (from 36 percent to 60 percent, shown in appendix B) was multiplied by the estimated percentage of valid reservoir sections determined in step 2 to obtain an estimate of the percentage of reservoir sections that represent volumetrically, time-wise, geometrically, and barically valid[2] reserve growth in the total Frio group. Based on these calculations, from 18 to 30 percent of the reservoir sections within the Frio >20 top-half group represent within-reservoir reserve growth.

A. Calculation of reservoir section percentages.

	Reservoir-section type	Number of sections	Percent
All reservoir sections in the >20 top half, densities 2–4			
	Consolidated	1	0.8
	Cycled	25	21
	Different, overlapping, same, and water drive	49	41
	Faulty data	10	8
	Examined[3]	16	13
	Not examined	19	16
	Total	120	100
Subset of classified reservoir sections in the >20 top half, densities 2–4			
	Different sandstone	14	29
	Overlapping	2	4
	Same sandstone	30	61
	Water drive	3	6
	Total	49	100

[1]Geometrically valid reservoir-section types in the Frio are same-sandstone, water-drive, and overlapping reservoir sections considered to represent within-reservoir reserve growth. Perforations in these reservoir sections probably contact a single reservoir, and sandstone stringers are separated by 30 ft of shale or less.

[2]Barically valid—Pressures available from public records indicate that perforations in the sandstone bodies within a reservoir section are probably not in pressure communication.

[3]Section partially complete—some well logs examined but type not determined.

Table 3 (cont.)

B. Calculation of percentage of reservoir sections estimated to represent within-reservoir reserve growth.

Calculation	Sample equation for Frio >20 top-half group	Result (%)
Total percentage of reservoir sections minus percentage of consolidated, cycled, and faulty data types (= percentage of remaining sections)	100 – 0.8 – 21 – 8 =	70
Different-sandstone percentage multiplied by percentage of remaining sections	70 × 29 =	20
Different-sandstone percentage subtracted from percentage of remaining sections	70 – 20 =	50
Percentage of same-sandstone sections estimated to represent reserve growth (from app. B) applied to same/overlapping percentage of remaining sections	50 × (36 to 60) =	18 to 30

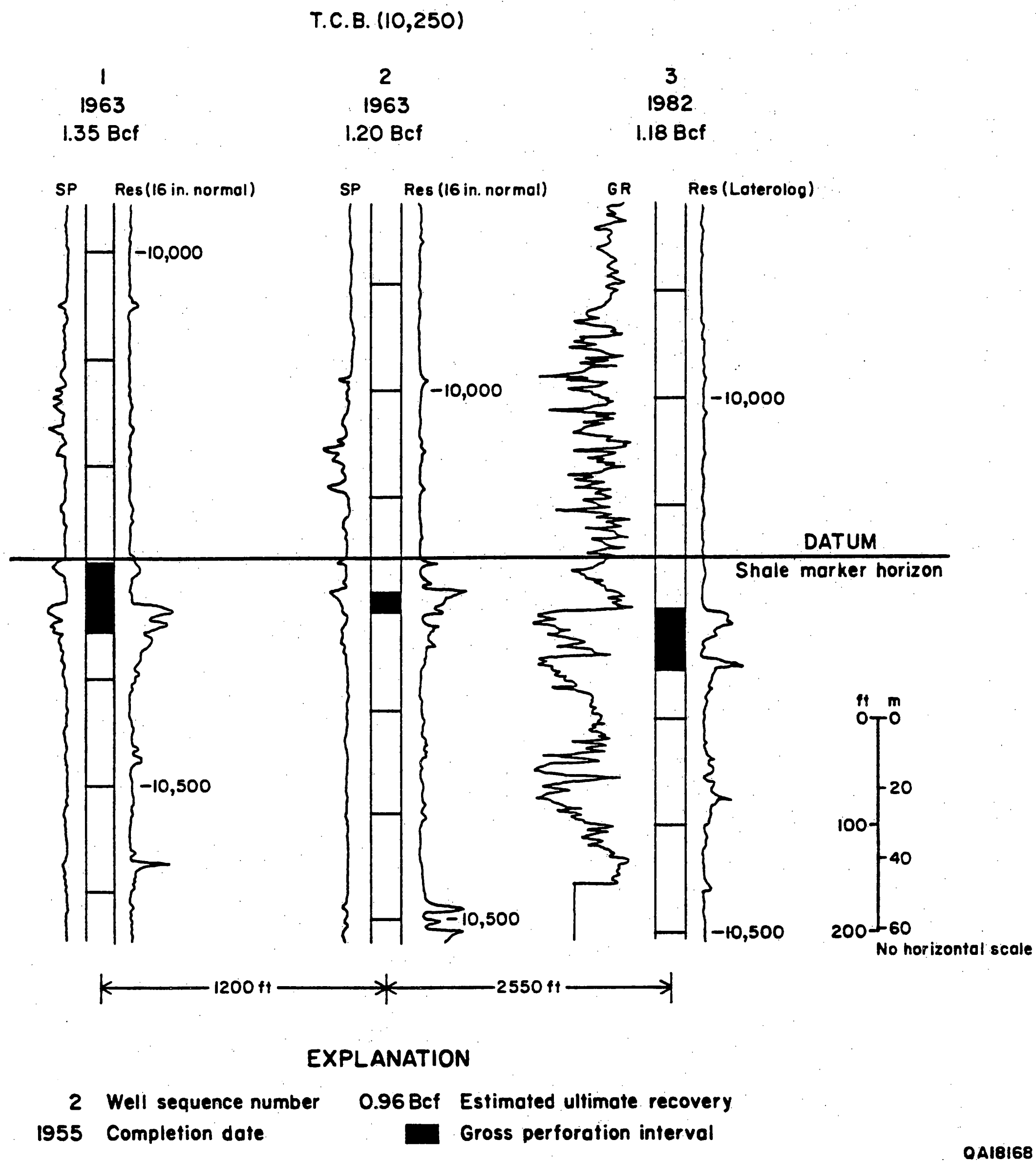

Figure 32. Reservoir section in T.C.B. field, 10,250 reservoir, showing overlapping-sandstone completions interpreted to be in delta-front sandstones. REUR of this section is 0.92. Field located in figure 12.

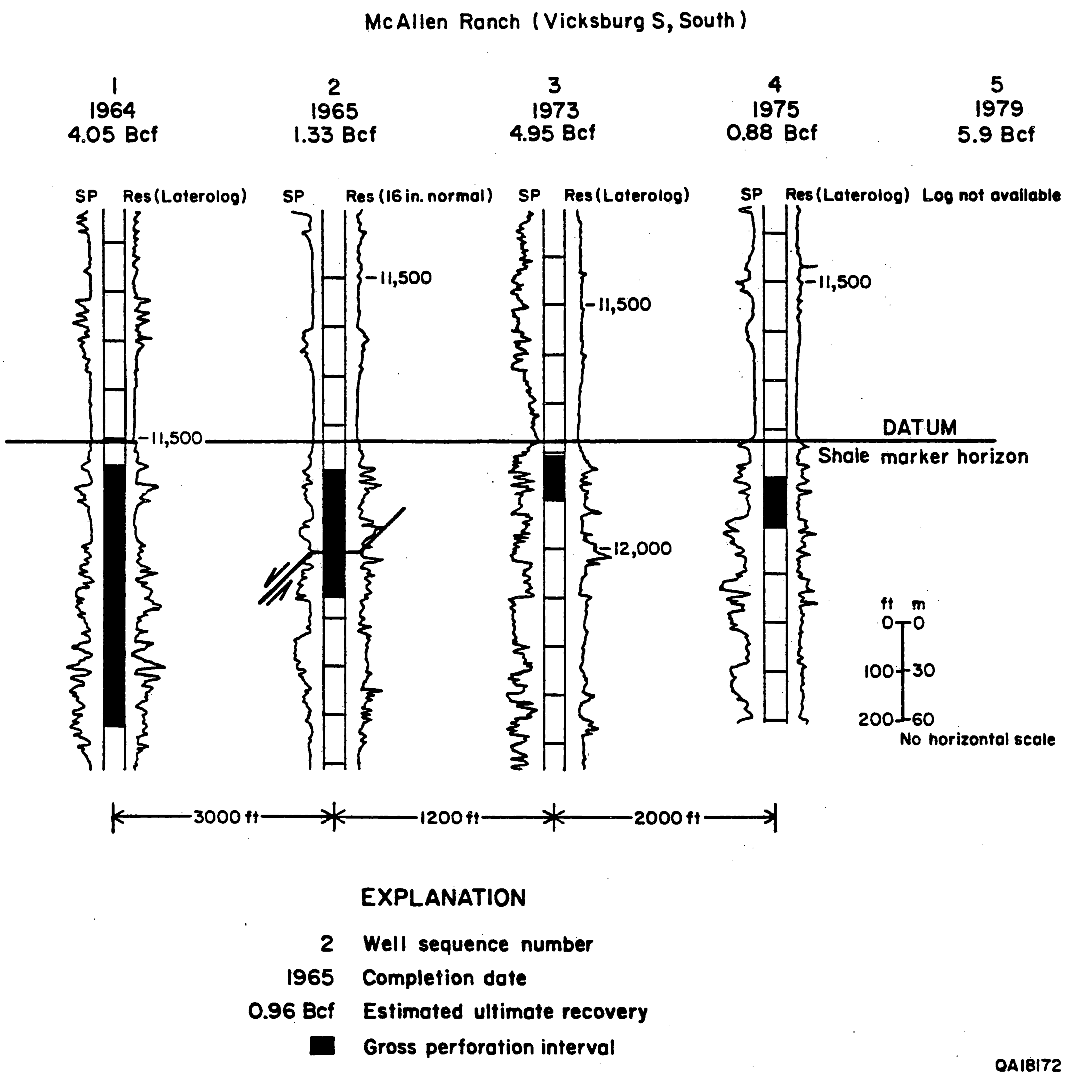

Figure 33. Reservoir section in McAllen Ranch field, Vicksburg S, South reservoir, showing overlapping-sandstone completions in faulted delta-front sandstones. REUR of this section is 0.49. Field located in figure 12.

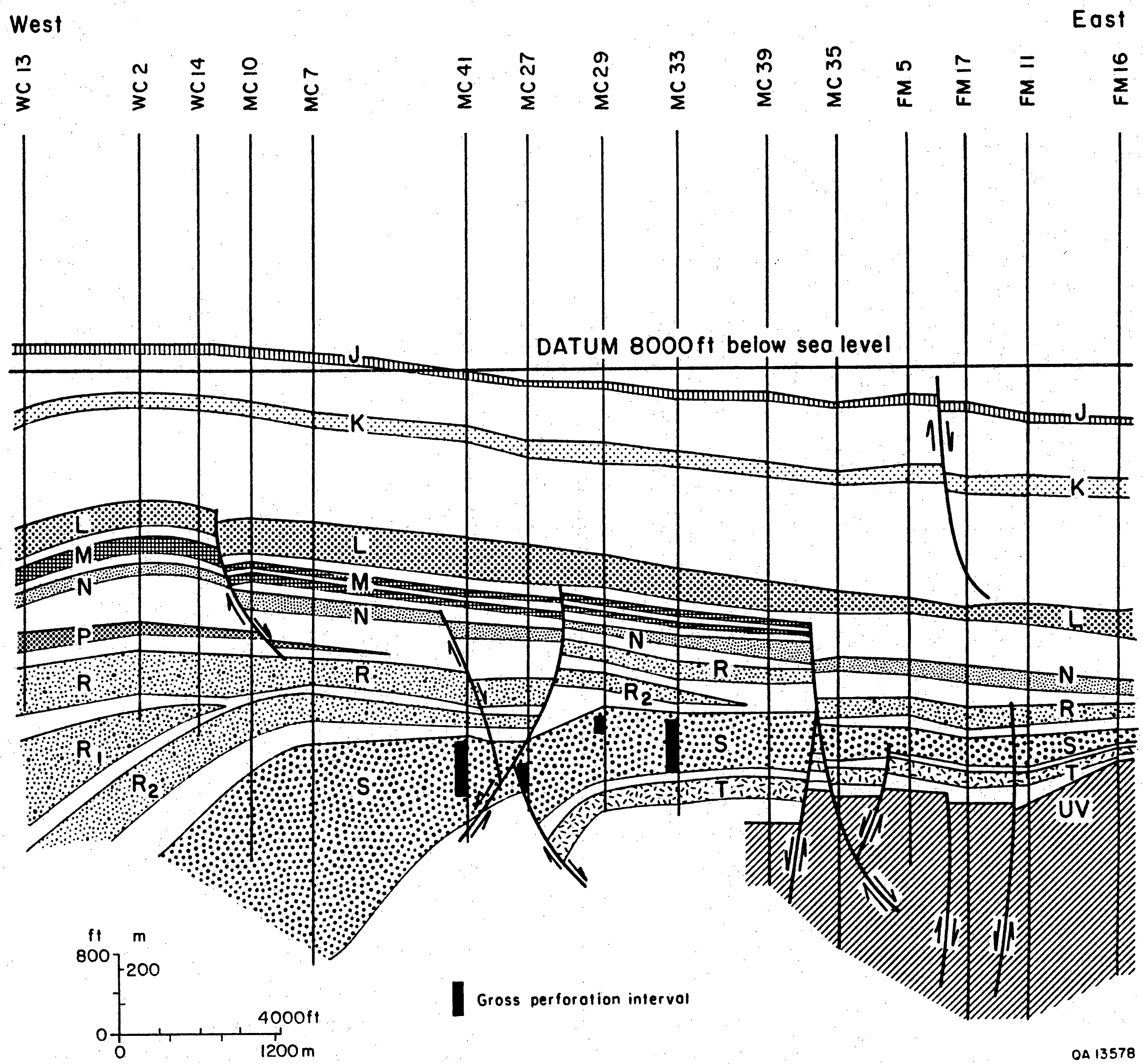

Figure 34. Dip-oriented structural cross section in McAllen Ranch field showing overlapping completions and structural complexity in the S reservoir. Completions in wells MC 41 and MC 27 on the west and in well MC 33 on the east are listed in the Vicksburg S, Southeast reservoir, and the completion in well MC 29 is listed in the Vicksburg S, South reservoir. The complex stratigraphic and structural relations in this field were not known in detail until recent years. Modified from Langford and others (in press).

complex deltaic reservoirs create targets for significant volumes of reserve growth (Langford and others, in press).

3. *Different sandstone*, where completions in sandstones are separated by more than 30 ft of shale.

4. *Water-drive* reservoirs, where thick, permeable sandstone units allow aquifers to maintain pressure in a gas reservoir.

5. *Cycled/injected* reservoirs, where gas withdrawn from the reservoir is reinjected into the same reservoir for pressure maintenance.

6. *Consolidated* reservoirs, where two or more single reservoirs are coproduced from the same well.

7. Reservoir sections with *faulty data*.

Implications for estimation of reserve growth from Vicksburg reservoir-section types are detailed in the following paragraphs, abbreviated where they are similar to those of the Frio Formation.

1. *Same sandstone*—Reserve growth from same-sandstone completions is considered valid relative to within-reservoir reserve growth when infill well production is from partially or totally untapped compartments in a reservoir.

2. *Overlapping*—Reserve growth from overlapping completions in the Vicksburg Formation is viewed in a more conservative way than reserve growth from overlapping completions in the Frio Formation because of length, complex geometry, and wide variation in the gross perforation intervals involved. Overlapping completions in this unit commonly span 200 ft in a single well and from 200 to 1,000 ft, incorporating several discrete sandstone units in a single section. Some completions are cut by faults, and faults cut the strata between wells. Vicksburg overlapping completions are not geologically appropriate for use in estimation of within-reservoir reserve growth.

3. *Different sandstone*—The use of REUR values from different-sandstone completions to predict within-reservoir reserve growth is not geologically appropriate.

4. *Water drive*—Reserve growth from water-drive reservoirs is governed by different processes than is reserve growth from pressure depletion-drive reservoirs. Therefore, it may be inappropriate to use REUR values from water-drive reservoir sections for prediction of reserve growth from depletion-drive reservoirs when pressure data suggest continuity of reservoir units.

5. *Cycled/injected*—Production volumes from completions in cycled and gas-injected reservoirs include injected gas volumes. REUR values in cycled reservoir sections are inappropriate on an engineering basis for prediction of reserve growth.

6. *Consolidated* reservoirs are inappropriate for prediction of reserve growth.

7. *Faulty data*—REUR values from these reservoir sections are mathematically inappropriate for use in reserve growth prediction.

Geologic complexity combined with extensive overlapping perforation geometries in Vicksburg deltaic strata indicate that playwide production histories may be invalid in within-reservoir gas reserve growth estimation. Same-sandstone completion geometries that may be appropriate for geologically based, within-reservoir reserve growth estimation represent an estimated 42 percent of Vicksburg reservoir sections with well densities from 2 to 4, PPY values >20, and REUR values in the top 50 percent used in the EEA analysis (table 4, app. D).

Wilcox Reservoir-Section Types

Same-sandstone, Lobo sandstone, and consolidated reservoir-section types were identified in the Wilcox Group:

1. *Same sandstone*, where completions in sandstone stringers are separated by 30 ft of shale or less (fig. 16).

2. *Lobo sandstone*, where completions in sandstones are consolidated and/or in reservoirs designated as tight on a regulatory basis. Reservoir limits in Lobo sandstones are difficult to determine because of the multiple unconformities and abundant growth faults in the Lobo play (fig. 17). In addition, many Lobo reservoirs have less than 0.1 millidarcy of in situ permeability, and hydraulic fracturing is a common completion practice. Eighteen (32 percent) of the Lobo reservoir sections in the 10- to 20-yr PPY group are designated as tight-sandstone reservoirs.

3. *Consolidated* reservoirs, where two or more single reservoirs are coproduced from the same well.

Implications for estimation of reserve growth from Wilcox reservoir-section types are:

Table 4. Summary of reservoir-section types identified in Vicksburg reservoir sections with PPY values >20 and REUR values in the top 50 percent (Vicksburg >20 top half). For calculation of percentage of reservoir sections estimated to represent reserve growth on a geometrical basis see table 3. Note that overlapping types were not considered to represent geometrically valid reserve growth in Vicksburg reservoirs.

	Reservoir-section type	Number of sections	
All reservoir sections in the >20 top half, densities 2–4			
	Consolidated	1	
	Cycled	2	
	Different, overlapping, same, and water drive	13	
	Faulty data	4	
	Examined[1]	6	
	Not examined	5	
	Total	31	
Subset of reservoir sections in the >20 top half, densities 2–4			
	Different sandstone	2	
	Overlapping	4	
	Same sandstone	4	
	Water drive	3	
	Total	13	
Percentage of reservoir sections in the >20 top half, densities 2–4 group estimated to represent reserve growth on a geometrical basis			42%

	Reservoir-section type	Number of sections	
All reservoir sections in the >20 top half, densities >4			
	Consolidated	0	
	Cycled	0	
	Different, overlapping, same, and water drive	1	
	Faulty data	0	
	Examined	5	
	Not examined	1	
	Total	7	
Subset of reservoir sections in the >20 top half, densities >4			
	Different sandstone	0	
	Overlapping	1	
	Same sandstone	0	
	Water drive	0	
	Total	1	
Percentage of reservoir sections in the >20 top half, densities >4 group estimated to represent reserve growth on a geometrical basis			insufficient data

[1]Section partially complete—some well logs examined but type not determined.

1. *Same sandstone*—Reserve growth from same-sandstone completions is considered valid for within-reservoir reserve growth when infill well production is from partially or totally untapped compartments in the reservoir.

2. *Lobo sandstone*—Lobo sandstone completion geometry is similar to consolidated reservoir geometry, because two or more separate reservoirs are produced as a single unit. Prediction of within-reservoir gas reserve growth based on REUR values from both Lobo and same-sandstone reservoirs is geologically invalid when attempting to assess reserve growth due to reservoir compartmentalization.

3. *Consolidated*—REUR values from consolidated reservoirs are inapplicable to prediction of within-reservoir reserve growth.

Same-sandstone reservoir sections where infill completions contact incremental gas volumes are considered most appropriate for use in prediction of geologically based, within-reservoir reserve growth in Wilcox reservoirs in district 4. Prediction of reserve growth using REUR values from Lobo reservoir sections (50 percent of the reservoir-section group with densities from 2 to 4, PPY values >10, and REUR values in the top 50 percent [table 5, app. E]) is related to limitations of drainage radius in a tight matrix and not to depositional or diagenetic heterogeneity. Lobo reservoir sections make up 42 percent of the reservoir-section group with densities from 2 to 4, PPY values >10, and REUR values in the bottom 50 percent and 49 percent of the 0 to 10 PPY group. Wilcox reservoir sections with densities >4 were not identified by EEA.

Miocene Reservoir-Section Types

In the Miocene strata, same-sandstone, different-sandstone, water-drive, and faulty data reservoir section types were identified:

1. *Same sandstone*, where completions in sandstone stringers are separated by ≤30 ft of shale (fig. 19).

2. *Different sandstone*, where completions in sandstones are separated by >30 ft of shale (fig. 35).

Table 5. Summary of reservoir-section types identified in Wilcox reservoir sections with densities from 2 to 4, PPY values >10, and REUR values in the top 50 percent (Wilcox >10 top half). For calculation of percentage of reservoir sections estimated to represent reserve growth on a geometrical basis see table 3.

	Reservoir-section type	Number of sections	
All reservoir sections in the >10 top half, densities 2–4			
	Consolidated	1	
	Cycled	0	
	Lobo sandstone	15	
	Same sandstone	4	
	Faulty data	0	
	Examined[1]	4	
	Not examined	6	
	Total	30	
Subset of reservoir sections in the >10 top half, densities 2–4			
	Same sandstone	4	
Percentage of reservoir sections in the >10 top half, densities 2–4 group estimated to represent geometrically valid reserve growth			47%

[1]Section partially complete—some well logs examined but type not determined.

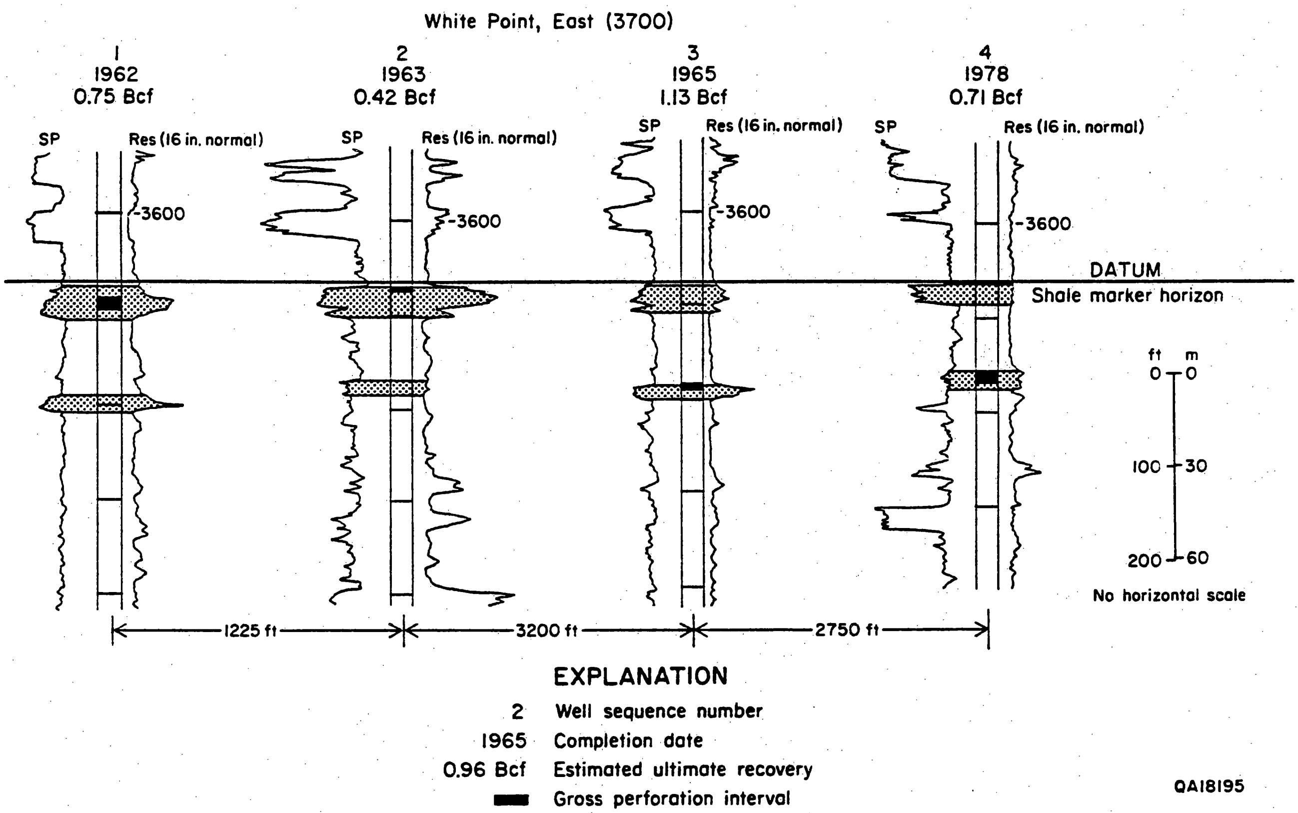

Figure 35. Reservoir section in White Point, East field, 3700 reservoir, showing different-sandstone completions interpreted to be in Miocene braided-stream deposits. REUR of this section is 0.92. Field located in Figure 18.

3. *Water-drive* reservoirs, where thick, permeable sandstone units allow aquifers to maintain pressure in a gas reservoir (fig. 20). Thick sandstones containing aquifers are present in both plays 1 and 2.

4. Reservoir sections with *faulty data*.

Implications for estimation of reserve growth from Miocene reservoir-section types are:

1. *Same sandstone*—Reserve growth from same-sandstone completions is considered valid for within-reservoir prediction of reserve growth when infill well production is from partially or totally untapped compartments in the reservoir.

2. *Different sandstone*—The use of REUR values from different-sandstone completions to predict geologically based, within-reservoir reserve growth is inappropriate.

3. *Water drive*—Because reserve growth from water-drive reservoirs is governed by different processes than is reserve growth from pressure depletion-drive reservoirs, it is not geologically appropriate to use REUR values from water-drive reservoir sections for prediction of reserve growth from depletion-drive reservoirs when pressure data suggest continuity of reservoir units.

4. *Faulty data*—Reservoir sections with faulty data are not mathematically appropriate for use in reserve growth prediction.

Same-sandstone Miocene reservoir sections where infill completions contact incremental gas volumes, less than 76 percent of the geometrically valid reservoir sections with densities of 2–4, PPY values >20, and REUR values in the top 50 percent, are considered most suitable for use in prediction of geologically based, within-reservoir reserve growth in district 4 (table 6, app. F). Miocene reservoir sections with densities >4 were not identified by EEA.

Discussion

Frio, Vicksburg, Wilcox, and Miocene reservoir sections were analyzed to geologically verify the prediction of reserve growth indicated by the EEA macro analysis. Frio reservoir-section types include same-sandstone, different-sandstone, cycled, consolidated, and water drive. Of these types, the same-sandstone reservoir sections are most appropriate for within-reservoir estimation of reserve growth

Table 6. Summary of reservoir-section types identified in Miocene reservoir sections with densities from 2 to 4, PPY values >20, and REUR values in the top 50% (Miocene >20 top half). For calculation of percentage of reservoir sections estimated to represent reserve growth on a geometrical basis see table 3.

	Reservoir-section type	Number of sections	
All reservoir sections in the >20 top half, densities 2–4			
	Different, same, and water drive	12	
	Faulty data	4	
	Examined[1]	10	
	Not examined	21	
	Total	47	
Subset of reservoir sections in the >20 top half, densities 2–4			
	Different sandstone	2	
	Same sandstone	6	
	Water drive	4	
	Total	12	
Percentage of reservoir sections in the >20 top half, densities 2–4 group estimated to represent geometrically valid reserve growth			76%

[1]Section partially complete—some well logs examined but type not determined

through advanced development of depositionally heterogeneous reservoirs. Volumetrically, EEA determined that the Frio Formation in district 4 has the highest infill reserve growth potential. However, only same-sandstone infill completions that tap partially or totally isolated compartments are geologically valid for use in prediction of within-reservoir Frio reserve growth. These reservoir sections are estimated to represent 20 to 33 percent of the >10-PPY reservoir sections used in the EEA analysis. The implications of these results are summarized in the Discussion and Conclusions section of this report.

Vicksburg, Wilcox, and Miocene strata also have relatively high potential for infill reserve growth in district 4 (Energy and Environmental Analysis, Inc., 1990). Geologic complexity in the Vicksburg, combined with extensive overlapping perforation geometries in tight reservoirs, suggests that use of REUR values calculated from these types of reservoir sections is unsuitable for prediction of within-reservoir reserve growth attributable to reservoir heterogeneity. Same-sandstone completion geometries represent an estimated 42 percent of Vicksburg reservoir sections used in the EEA analysis. A portion of these, if determined to have infill completions in partial or total pressure isolation from previous completions, represent within-reservoir reserve growth in the Vicksburg.

In the Wilcox Group, EEA reserve growth prediction includes Lobo and non-Lobo reservoir sections in a single estimate. Completion geometries in Lobo reservoir sections represent a combination of as many as six geologically different reservoirs and are not appropriate for within-reservoir reserve growth prediction. In the EEA analysis, Lobo reservoir sections make up 50 percent of the reservoir-section group with densities from 2 to 4, PPY values >10, and REUR values in the top 50 percent, 42 percent of the reservoir-section group with densities from 2 to 4, PPY values >10, and REUR values in the bottom 50 percent, and 49 percent of the remaining Wilcox reservoir sections (<10 PPY group).

Reserve growth prediction in Miocene reservoirs may be most accurate if same-sandstone reservoir sections are used. Same-sandstone reservoir sections represent an estimated 76 percent of Miocene reservoir sections used in the EEA analysis. Only a portion of these reservoir sections represent reserve growth from partially or totally untapped reservoir compartments.

In the district 4 geologic units examined, the EEA infill gas reserve growth analysis includes new-pool reserve growth as well as within-reservoir incremental gas resources. Complex production and completion histories and stratigraphic and structural relations in Tertiary siliciclastic reservoirs must be taken into account in a geologically based reserve growth analysis. The large-scale view, although prone toward an overestimate, does show that reserve growth is significant and points to the need for specific detailed work to define reserve growth opportunities.

RESERVE GROWTH IN RELATION TO FRIO GAS PLAYS

Inter-play and Intra-play Evaluation

Frio plays are defined on the basis of common depositional environments specific to each play. Sandstone thickness is highest in fluvial-deltaic and deltaic plays (plays 1, 2, 3, 4, and 6) and lowest in barrier island, updip fluvial, and coastal plain plays (plays 5, 7, and 8) (Galloway and others, 1982). Correspondingly, play-wide averages of infill well production (as determined by the youngest completion in each reservoir section), first-well production (as determined by the class of the reservoir section), completion depth, and perforation thickness (overall interval) show a clear play distribution that generally correlates with sandstone-thickness characteristics (table 7). Specifically, the deltaic plays (plays 1, 2, and 3) and the cycled and consolidated sections, which are predominantly in plays 3 and 4 (see app. C), show high volumes of infill well production, high first-well production, and thick perforation intervals. Sandstones in these plays are abundant (averaging 35 percent of the total sediment thickness), gas-prone, and highly permeable (Galloway and others, 1982). Plays 6 and 4 have intermediate values for last-well and first-well production, completion depth, and perforation interval. Although play 6 contains barrier-island sandstones, and the sediments average a relatively high 48 percent gross sandstone thickness (Galloway and others, 1982), the gas volume produced from play 6 is lower because the thick barrier-island sandstones contain large volumes of water, and gas is commonly present only in the uppermost 100 ft of each unit. Play 4 contains fluvial sandstones that average a lower 27 percent gross sandstone thickness, in addition to thicker, higher-sandstone-percent deltaic sandstones. Sandstone-poor plays 7, 5, and 8 rank lowest in infill and first-well production, completion depth, and perforation

Table 7. Play averages of Frio reservoir-section characteristics ranked by average EUR[1] of the last (youngest) completion in each section.

Play	Average EUR of last well in section	Average perforation depth of last well in section	Average perforation interval[2] of last well in section	Average density	Average class	Average REUR	Number of reservoir sections
1 (distal deltaic)	2591291	8380	14	2	1.17	0.2412	7
3 (proximal deltaic)	2089390	8615	66	3	1.51	0.5641	47
2 (delta flank)	1912575	7532	46	2.7	1.51	0.3500	52
cycled and consolidated	1749897	6721	24	2.9	1.51	0.3487	62
6 (downdip barrier/strandplain)	1131876	7336	77	2.9	1.08	0.3822	51
4 (fluvial-deltaic)	765935	5564	20	2.7	1.05	0.4491	152
7 (updip barrier/strandplain)	743010	5728	16	2.1	0.82	0.7588	10
5 (updip fluvial)	189370	3677	7	2.8	0.64	0.3267	38
8 (fluvial/coastal plain)	114700	3284	7	2.5	0.53	0.4148	14
3 (proximal deltaic)	2089390	8615	66	3	1.51	0.5641	47
3A (southern part)	2047231	8033	63	2.8	1.66	0.5162	31
3B (northern part)	2173707	9712	71	3	1.24	0.6542	16
4 (fluvial-deltaic)	765935	5564	20	2.7	1.05	0.4491	152
4A (northern part)	743623	5957	16	2.6	1.10	0.4289	76
4B (southern part)	788247	5171	24	2.7	1.00	0.4694	76
6 (downdip barrier/strandplain)	1131876	7336	77	2.9	1.08	0.3822	51
6A (southern part)	1086122	6754	11	3.2	1.12	0.3104	25
6B (northern part)	1177630	7917	142	2.7	1.04	0.4539	26

[1]Estimated ultimate recovery

[2]Perforation interval represents the gross interval across which perforations are placed.

thickness. These inter-play trends reflect well-known geologic parameters and expected production characteristics—thicker reservoir pay and higher pressures correlate with increased production.

Intra-play differences in production and completion characteristics were examined in plays 3, 4, and 6 (table 7). Although not statistically significant, trends within the plays again indicate that regions with greater sandstone thickness, often as a result of deeper structural position and thickening across growth faults, have high infill well and first-well productions, deep completion depths, long perforation intervals, and high well densities. These trends reflect known geologic and engineering characteristics but do not further define controls on parameters determining reserve growth. A more detailed analysis of the Frio fluvial-deltaic play (play 4) with direct bearing on reserve growth prediction can be found in Ambrose and others (in press).

REUR Value Assessment

No correlation with play type or any geologic parameter was identified for REUR values because the REUR is affected by geologic, engineering, and economic parameters that vary widely within and between plays and within and between reservoir-section types. To illustrate this variation, REUR values were examined for reservoir sections with nearly identical characteristics: within-play, same-sandstone, same-density reservoir sections in the high-reserve-growth group. Thus, all of the reservoir sections in the REUR-value study sample represent similar depositional environments, are within single reservoirs, have the same number of completions, and have an infill well in each section that clearly represents reserve growth. REUR values varied by 0.05 (13 percent) between two of the selected reservoir sections with similar perforation intervals and completion depths (table 8). If one of these two characteristics was varied, for example in a comparison of two selected reservoir sections with similar perforation intervals but different completion depths, REUR values varied by 0.11 (58 percent). If two factors were varied within the selected sample, as in a comparison of two reservoir sections with different completion depths and perforation thicknesses, the REUR values varied by 0.28 (102 percent). These wide variations in REUR values between reservoir sections with similar geologic and production characteristics show why REUR

Table 8. Comparison of REUR values in reservoir sections with similar characteristics. These Frio reservoir sections are of the same-sandstone type and have well densities from 2-4, PPY values >20, REUR values in the top 50 percent, and have pressures interpreted to represent reserve growth.

Reservoir section Field (reservoir)	Upper[1]	Lower[1]	Density	Class	EUR of last well (Bcf)	REUR	Play
Los Indios (M)	6834	6867	2	1	1037844	0.387	4B
Los Indios (G)	6202	6220	2	0	177052	0.4443	4B
REUR difference						0.0573	
REUR average						0.4156	
						0.0573/.4156	
Percent REUR difference						=13	
Candelaria (9600)	9655	9670	3	2	960213	0.1374	3
Alazan, North (H-36, N.)	7347	7358	3	0	60678	0.2521	3
REUR difference						0.1147	
REUR average						0.1948	
						0.1147/0.1948	
Percent REUR difference						=58	
Santa Rosa (10700)	11123	11322	3	2	3669047	0.4227	3
Candelaria (9600)	9655	9670	3	2	960213	0.1374	3
REUR difference						0.2853	
REUR average						0.2800	
						0.2853/0.2800	
Percent REUR difference						=101	

[1]Perforation

values could not be correlated with parameters such as play, reservoir-section type, completion depth, or perforation interval.

Discussion

The play distribution of same-sandstone, reserve-growth reservoir sections suggests that more depositionally controlled reserve growth potential will be found in deltaic and fluvial-deltaic Frio plays in sandstone-rich facies characterized by relatively high heterogeneity. Plays dominated by relatively homogeneous facies, such as the downdip barrier-island/strandplain play, appear to have less reserve growth potential. Examination of the factors affecting the REUR value of a reservoir section indicates that, because the REUR results from a combination of stratigraphic and production characteristics, no correlation of REUR with other parameters exists.

DISCUSSION AND CONCLUSIONS

Analysis of Results

Statistical analyses using a macro-scale approach for prediction of reserve growth must account for stratigraphic and structural complexity as well as variations in production histories caused by geologic, engineering, and economic factors. In the EEA macro-scale study, which served as a starting point for this analysis, all the REUR values of different-sandstone, cycled, and same-sandstone completions within each class and density of reservoir section were grouped together. Such an approach results in a reserve growth estimate that includes both within-reservoir and new-pool volumes. Although both volumes are valid components of reserve growth, this analysis focused on the within-reservoir reserve growth potential associated with reservoir heterogeneity (depositional and diagenetic variability). Assessments of stratigraphy and sandstone geometry determined whether perforated zones were within the same depositional interval such that a single-sandstone reservoir was involved. Development of shallower and deeper new pools and infill development of pervasively tight reservoirs, such as the Wilcox Lobo trend, represent reserve growth but not within-reservoir or within-sandstone reserve growth related to reservoir heterogeneity as defined herein.

In the EEA macro-scale analysis, reservoir sections with the highest infill potential are those with densities from 2 to 4, PPY values >20, and REUR values in the top 50 percent. Within this group an estimated 55 percent of Frio, 42 percent of Vicksburg, 47 percent of Wilcox, and 76 percent of Miocene reservoir sections represent geometrically valid, within-reservoir reserve growth. The Wilcox Lobo trend was excluded in compilation of these percentages. An expanded analysis of Frio Formation reservoir sections using pressure data available in the public sector shows that 33 percent of the reservoir sections represent definite and possible reserve growth. This percentage was validated by single-reservoir geometric and pressure analyses for well densities from 2 to 4, PPY values >10, and REUR values from 0 to 3. In the ≥5 well-density Frio group for PPY values >20 and REUR values from 0 to 3, 19 percent of the reservoir sections (one-third less than the 2–4-density group) are estimated to represent definite and possible within-reservoir reserve growth. This decrease in valid reservoir sections with an increase in well density reflects the higher percentage of cycled and consolidated reservoir sections in reservoir sections with high well densities.

Reserve growth defined by reservoir-section analysis was used to estimate reserve growth potential (EEA, 1990). Infill volume estimates for the Frio (1,780 Bcf), Vicksburg (382 Bcf), Wilcox (626 Bcf), and Miocene (213 Bcf) comprise 95 percent (3,001 Bcf) of the 3,135 Bcf low-end, residual approximation estimate for all stratigraphic units in district 4 based on the EEA analysis. This estimate assumes that an asymptotic value of reserve growth (10 to 20 percent of initial production) is approached as a reservoir ages. The cohort mean EEA infill volume estimate for all units was 7,248 Bcf, and Frio, Vicksburg, Wilcox, and Miocene volumes are 95 percent of that estimate also. This estimate is the average production of all infill wells produced after 20 yr of reservoir life (5 to 100 percent of initial production). See EEA (1991) for additional explanation of the estimate types. Future infill reserve growth volumes were estimated by increasing all remaining single-well reservoir sections in district 4 to a density of four wells per section and applying incremental production volumes defined by the two methods to reservoir sections with well densities from 2 to 4 and REUR values from 0 to 3.

A revised infill reserve growth estimate was made herein by evaluating the percentage of each reservoir-section type that contributed to the EEA infill reserve growth prediction (tables 9 and 10). An estimated 25 percent of the 3,001 Bcf EEA infill estimate is contributed by extrapolation from consolidated, cycled, and faulty data reservoir section types. Reserve growth in consolidated and cycled reservoir sections is difficult to document but may occur in both same- and different-reservoir types. Reservoir sections with faulty data occur across all types of reserve growth and in some examples that do not represent reserve growth. An estimated 22 percent and 11 percent of the EEA infill estimate is represented by extrapolation from new-pool and Lobo-reservoir reserve growth, respectively. Nineteen percent of the EEA estimate represents definite and possible within-reservoir reserve growth in Frio reservoirs, and 23 percent of the estimate represents extrapolation from reservoir sections within a single reservoir that may or may not represent reserve growth.

Some 660 Bcf of EEA's estimate of 3,001 Bcf consists of gas volumes extrapolated using consolidated reservoir groups, cycled reservoirs, and reservoirs for which available data were determined to be incorrect (table 10). At least half that volume (330 Bcf) should be removed from the estimate, in our judgment, leaving a revised estimate of 2,671 Bcf; a more precise correction cannot be determined with the information available for this study. Within the 2,671 Bcf, 334 Bcf was extrapolated from Frio Formation reservoir sections representing rate acceleration of production from additional wells draining gas volumes already contacted (table 10). If this volume is deducted, and if the estimate volume from low-permeability Wilcox Lobo reservoirs is excluded from the district 4 reserve growth estimate, then the estimate is further reduced to 2,024 Bcf, or 67 percent of the original EEA estimate for the four stratigraphic intervals investigated. This volume can be referred to as a data- and permeability-adjusted estimate. It represents a substantial potential resource within known fields and results from reserve growth estimates based on validated data, excluding a major low-permeability trend where limited drainage radii lead to expected reserve growth. However, some low-permeability reservoir volumes remain in the adjusted estimate, predominantly volumes from reservoirs in the Vicksburg Formation.

A further disaggregation of the 2,024 Bcf estimate is made based on geometric and pressure verification of production. A value of 330 Bcf represents the remaining half of the 660 Bcf contained in the

Table 9. Types of reserve growth included in the EEA estimate of nonassociated gas infill potential in district 4 (EEA, 1990). Percentage data are from tables 2–6. Percentages for Vicksburg and Miocene units were calculated for reservoir sections with PPY values >20 and REUR values in the top 50 percent; however, they are being used to represent all PPY values and both top and bottom REUR-value groups in this table. This practice is supported by the fact that among the Frio and Wilcox reservoir sections analyzed, all PPY and REUR groups show similar percentage values.

Geologic unit	Estimated reserve growth potential (Bcf)	Reserve growth (%)	Type of reserve growth
Frio	1,780		EEA estimate
	–534	30	Consolidated, cycled, and faulty data (undefined amount of within-reservoir and new pool reserve growth included)
	1,246		
	–411	33	New pool (different-sandstone)
	835		
	–501	60	Definite and possible as determined by pressure analysis (same-sandstone, overlapping, and water drive)
	334		Probably not, as determined by pressure analysis
Vicksburg	382		EEA estimate
	–88	23	Consolidated, cycled, and faulty data (undefined amount of within-reservoir and new pool reserve growth included)
	294		
	–135	46	New pool (different-sandstone and overlapping)
	159		Geometrically valid (only a portion of these are definite and possible)
Wilcox	626		EEA estimate
	–19	3	Consolidated (undefined amount of within-reservoir and new pool reserve growth included)
	–313	50	Lobo reservoirs
	294		Geometrically valid (only a portion of these are definite and possible)
Miocene	213		EEA estimate
	–19	9	Faulty data (undefined amount of within-reservoir and new pool reserve growth included)
	194		
	–33	17	New pool (different-sandstone)
	161		Geometrically valid (only a portion of these are definite and possible)

Table 10. Summary of reserve-growth types included in the EEA estimate of nonassociated gas infill potential in district 4. Data are from table 12. All units are in Bcf.

Type of reserve growth	Geologic unit				Total	Percent of revised estimate
	Frio	Vicksburg	Wilcox	Miocene		
Consolidated, cycled, and faulty data (undefined amount of within-reservoir and new pool reserve growth included)	534	88	19	19	660	25
New pool	411	135		33	579	22
Lobo			313		313	11
Definite and possible as determined by pressure analysis (same-sandstone, overlapping, and water drive)	501				501	19
Geometrically valid (only a portion of these are definite and possible)		159	294	161	614	23
Total reserve growth, revised estimate					2,667[1]	100
Probably not reserve growth, as determined by pressure analysis	334				+ 334	
EEA estimate for Frio, Vicksburg, Wilcox, and Miocene units					= 3,001	

[1] 89% of original EEA estimate of 3,001 Bcf in these geologic units

consolidated, cycled, and faulty data reservoir sections. A total of 1,115 Bcf represents within-reservoir reserve growth, and the remaining 579 Bcf represents shallower- or deeper-pool reservoirs determined not to be in pressure communication with preceding completions in a given reservoir section but nevertheless contributing to overall reserve growth. Thus, of an original estimate of 3,001 Bcf in four stratigraphic units in district 4 of South Texas, two-thirds of that volume was estimated to represent reserve growth in predominantly conventional permeability reservoirs, both connected (same-sandstone) and not connected (different-sandstone) (2,024 Bcf), and more than one-third (1,115 Bcf, or 37 percent) was estimated to represent reserve growth within the same reservoir. These results indicate that the use of reported reservoir nomenclature and perforation data must be verified by at least a sampling of geological and engineering data from the fields involved in order to disaggregate reserve growth estimates and to their contributing components. Across all permeability types (313 Bcf of Wilcox Lobo resources included) and all reservoir geometries, an estimated 78 percent (2,024 + 313, or 2,337 Bcf) of the initial reserve growth estimate (3,001 Bcf) was validated as part of this study. If this percentage is applied to the original cohort mean EEA infill estimate (7.2 Tcf), then 78 percent, or 5.2 Tcf, is validated as a reserve growth estimate. The volumes judged most appropriate for removal from the original EEA estimate are 330 Bcf (11 percent), based on incomplete accounting for cycled reservoirs and poor data, and 334 Bcf (11 percent), where pressure analysis suggests that no new gas has been tapped. The original EEA infill estimate also contains both infill and new-pool volumes. The distinction between total reserve growth and within-reservoir reserve growth due to depositional and diagenetic heterogeneity must remain clear in any discussion of reserve growth processes and estimates.

Future Work

An examination of high-density (≥5-well) reservoir sections may help to define areas with high reserve growth potential appropriate to a geologically based analysis of reserve growth potential in district 4. Same-sandstone, high-density reservoir sections are abundant in sandstone units with multilateral depositional geometry (described by Kerr, 1990). Examples of these types of reservoir sections are in the McAllen (Hansen) reservoir, Hidalgo County, interpreted to have a distal shoreface and barrier-island depositional origin, in the Agua Dulce (5450) and Kelsey (Zone 14-A) reservoirs in Nueces and Brooks Counties, interpreted to have a braided-stream depositional origin, and in the Madero (J-24) and Laguna Larga (B-1 IV, C-1 III, and C-1 IV) reservoirs in Kleberg County, interpreted as wave-reworked delta-front deposits. Investigations of these reservoirs to determine historical reserve growth and more regional investigation of within-play distribution of multilateral and multivertical sandstone geometries will benefit future reserve growth estimates in district 4.

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APPENDIX A. METHODOLOGY USED IN MACRO-SCALE INFILL ANALYSIS PROJECT, DISTRICT 4, TEXAS.

Gas field reserve growth analysis was performed by Energy and Environmental Analysis, Inc. (EEA) under contract to the Gas Research Institute (GRI) (EEA, 1991, 1990). The purpose of the project was to compile a large gas completion/location data base and to predict reserve appreciation potential from historical development trends in old fields by compiling statistics from infill, extension, new pool, and bypassed zone completions. Data from the EEA nonassociated gas reservoir infill analysis in Railroad Commission of Texas district 4 was used as the basis for development and analysis in this report.

The EEA analysis was made using groups of well completions called reservoir sections (table A-1). These groups were analyzed statistically and represented on plots of recovery ratio (REUR) versus prior production years (PPY) (figs. A-1 and A-2). Definitions and terminology are listed below.

A. Basic definitions

1. Reservoir section—a group of well completions made within a 640-acre area (a section) containing completions listed in Railroad Commission of Texas data as being in a single reservoir (table A-1). This is the EEA "unit" used to determine infill reserves on cross plots.

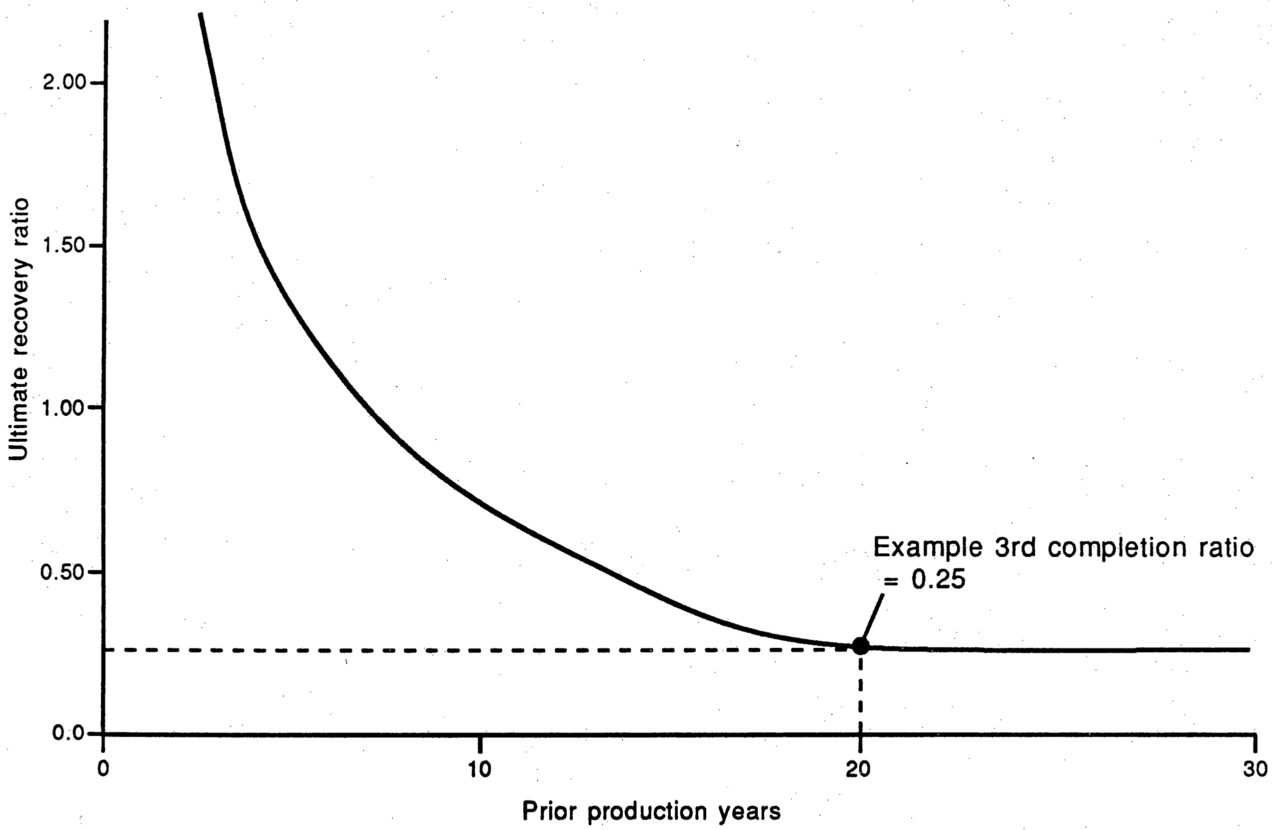
2. Reservoir section density—number of well completions in a reservoir section.

3. Class—rank of a reservoir section based on the estimated ultimate recovery (EUR), or actual recovery if the well is no longer active, of the initial completion in each reservoir section. For example, the "high" class of reservoir sections has initial completions with high estimated ultimate recoveries. EEA class designations are: high = 2, middle = 1, and low = 0. Class divisions were made by ranking the initial completions by EUR and dividing them into three equal parts; each part has the same number of completions.

B. Cross plot definitions

1. Estimated ultimate recovery ratio (REUR)—estimated ultimate recovery of the last completion made in a reservoir section divided by the average of estimated ultimate recoveries for all other completions in the section. The ratio is expressed as a decimal. For example, in a three-well reservoir section (density = 3) where the first well made 500 MMcf and the second well made 300 MMcf, the

(a) Infill crossplot



(b) Example reservoir section data

	Completion no. or cohort no.	Completion date	Prior production years	Ultimate recovery (MMcf)*
3-well reservoir section	1.....	1969	16 (1985-1969)	500
	2.....	1981	4 (1985-1981)	300
	3.....	1985	---	100
			20 years	

* Actual total production for wells no longer active or estimate for wells active in 1988

- Average recovery, completions 1 and 2 = 400 MMcf
- PPY = Prior production years = 20
- REUR = Ratio of 3rd to 1st and 2nd ultimate recoveries = 100/400 = 0.25

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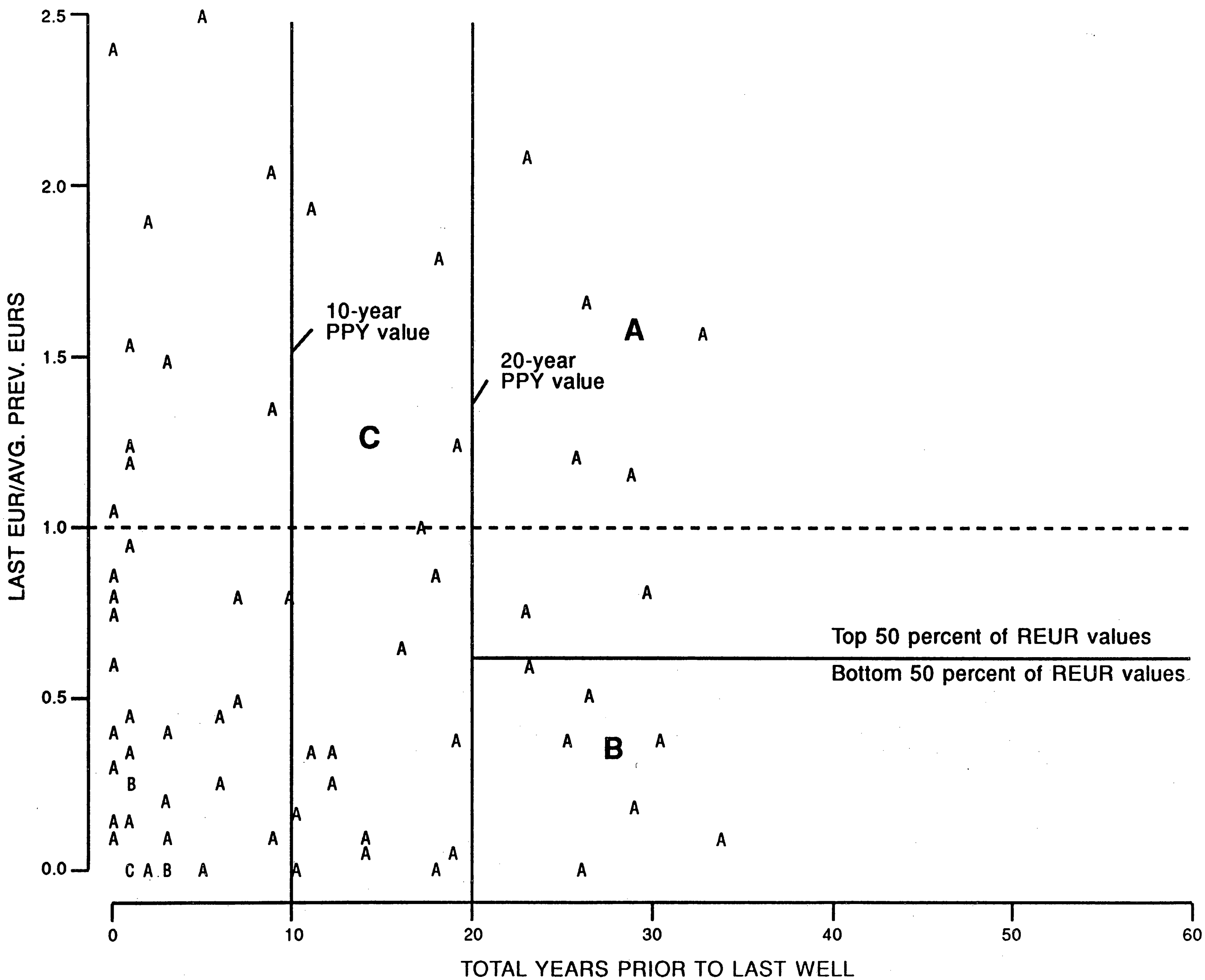
Figure A-1. EEA infill assessment methodology (adapted from EEA, 1990) showing example infill cross plot and method for calculating PPY and REUR.



Note: 24 observations had missing values or were out of range.

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Figure A-2. Example EEA infill analysis cross plot for class 0, density 2 Miocene reservoir sections. For clarity, additional data were added in areas A, B, and C. REUR is on the y-axis and PPY is on the x-axis. Reservoir sections examined in this report were predominantly in the >10 PPY-value range.

Table A-1. Example reservoir section (data as received from EEA) in the Donna (Rice) reservoir.

Reservoir	Lease name	Well no.	Completion year	Top of completion (ft)	Base of completion (ft)	Cohort or well sequence no.	Class	Estimated ultimate recovery (EUR)(mcf)	Estimated ultimate recovery ratio (REUR)	Prior years production
DONNA (RICE)	HOUSTON UNIT	2 L	59	6436	6456	1	2	3515008	0.4533	23
DONNA (RICE)	RICE GAS UNIT	3 L	82	6450	6490	2	2	1593512	0.4533	23

average is 500 plus 300 divided by 2 equals 400, and the ratio is 100 MMcf (production of last well) divided by 400 MMcf, or 0.25 (fig. A-1b). The EEA analysis excluded all reservoir sections with an REUR of 0.0 (last well production equal to 0.0), an undefined REUR (average production of previous completions equal to 0.0), and REURs greater than 3.0.

2. Total years prior to last completion (also called "prior production years" [PPY])—EEA reservoir section "age" determination, calculated by subtracting each earlier completion's date from the last completion date in a given reservoir section, and summing those values (fig. A-1b). For example, wells completed in 1969, 1981, and 1985 would produce a prior years' production value of 20 (16 plus 4) relative to the last well in 1985.

3. Infill analysis cross plot—a plot of the REUR versus the PPY of each reservoir section (figs. A-1a and A-2).

The analysis in this report concentrates on reservoir sections with the largest indicated reserve growth volumes, those having PPY values >20 and REURs in the top 50 percent of values (area A in fig. A-2). Implications of the validity of PPY and REUR values are discussed next.

A PPY value of >20 is inferred to imply that infill drilling has taken place. This is reasonably clear in a 2-well reservoir section in which the completions are 20 yr apart. However, in a 4-well reservoir section, the time span between the first and last completions could be as small as 7 yr, and a reservoir could still be under primary development at that time (see app. C, fig. C-1). Both of these types of completion configuration are used in the EEA infill assessment.

REUR values vary considerably depending on the relative volumes of the completions being evaluated (tables A-2 and A-3). For the same amount of increase in production between two wells, a small-production well pair will have a larger REUR than a large-production well pair. Large-REUR well pairs were eliminated from the EEA analysis, probably resulting in a lower gas reserve growth estimate than would be made if >3-REUR reservoir sections were included in the estimation process. It is difficult to estimate the increase in reserve growth volume that would be expected if reservoir sections with >3 REUR values were included in the EEA analysis. Reservoir sections with REUR values >3 represent 17 percent of Wilcox reservoir sections with densities from 2 to 4 and PPY values from 0 to 10. Reservoir sections with

>3 REUR values in Stratton field represent 12 percent of the total nonassociated gas reservoir section group (all densities, all PPY values), 7 percent of the >10-yr group, and 0 percent of the >20-yr group.

Table A-2. Comparison of REUR values in small and large-production theoretical reservoir sections. The REUR value decreases 10 times as production increases 110 times while net-volume increase remains the same.

Reservoir section	Well no. (cohort)	EUR (theoretical) (Mcf)	REUR
Section (1)	1	0.0100	
Section (1)	2	0.1000	
EUR difference =		0.0900	10
Section (2)	1	10.100	
Section (2)	2	11.000	
EUR difference =		0.0900	1.08

Table A-3. Frio reservoir sections examined with REUR values >3, ranked by REUR. Production volumes of completion 1 generally increase as REUR values decrease. A production anomaly was identified in only one of these sections (Stratton [C-5300]). All completion geometries are valid. One completion has no production; however, only reservoir sections with the last completion having no production were eliminated from the EEA analysis (REUR of those sections = 0).

Field (Reservoir)	EUR[1] Well 1	EUR Well 2	EUR Well 3	REUR	PPY	Density
Hinojosa (E-62)	437	56773	N.A.[2]	129.9153	15	2
Boyle (3100)	1648	156756	N.A.	95.1191	11	2
Stratton (5800)	13035	840831	N.A.	64.5056	1	2
Stratton (Wagner)	77157	3286193	N.A.	42.5910	1	2
Stratton (Arroyo, 4-6700)	84268	1609039	N.A.	19.0943	17	2
Stratton (R-5, 6750)	73183	276448	N.A.	9.0440	6	2
Stratton (F-39)	79147	689810	N.A.	8.7156	7	2
Stratton (E-31)	5551	35121	N.A.	6.3268	1	2
Boyle (3300)	0	125440	348843	5.5619	18	3
Kelsey Deep (Zone 60-H)	102158	11450	286428	5.0424	16	3
Stratton (C-5300)	304073	1525698	N.A.	5.0175	20	2

[1]Estimated ultimate recovery, in Mcf
[2]N.A. = not applicable

APPENDIX B. PRESSURE ANALYSES OF FRIO RESERVOIR-SECTION DATA.

Reservoir sections in the same-sandstone type and with densities from 2 to 4, PPY values >20, and REUR values in the top 50 percent were analyzed for pressure continuity. Two types of pressure analyses were used: (1) comparison of infill completion pressures with previous-completion pressures within a reservoir section and (2) pressure drawdown analysis between the last two completions in a reservoir section. Reservoir sections for each type of analysis were chosen at random. As a check on the analysis, two reservoir sections were analyzed by both methods. Both tests gave the same answer in each case.

For the pressure comparison of all completions in a reservoir section, all available pressure data were plotted against time and the initial pressure of the last (youngest) completion in the section compared with previous pressures and activity. Three types of last-well pressure characteristics were identified: (1) pressure not more than 500 psi above completions active at the time of the infill (expected pressure, previous wells active) (fig. B-1), (2) pressure not more than 500 psi above the abandonment pressure of older, shut-in or abandoned completions (abandonment pressure, previous wells inactive) (fig. B-2), and (3) pressure >500 psi above completion pressures measured at the time of the infill (fig. B-3). Experience with reservoir engineering tests performed in Stratton field for the Secondary Gas Recovery (SGR) project indicates that pressure differences as low as 300 to 400 psi may represent the existence of partial barriers to gas flow. The 500 psi cutoff used in this study is therefore considered to be a conservative value. More incremental gas may be contacted by infill wells than is suggested by the results of this sample.

Production from infill completions at expected pressures (50 percent of the sample, table B-1) probably do not represent reserve growth where preceding wells continue to produce. Production from infill completions at or near abandonment pressures when previous wells are inactive (17 percent of the sample) probably represent reserve growth, and infill pressures >500 psi above previous completions (33 percent of the sample) definitely represent reserve growth.

For the pressure drawdown analysis, a computer program from REC was used to estimate the position of drawdown curves between the two youngest completions in a reservoir section for a circular reservoir sandstone having a diameter or radius equal to the distance between the two wells. Engineering equations used to create the curves required permeability, net pay, porosity, water saturation,

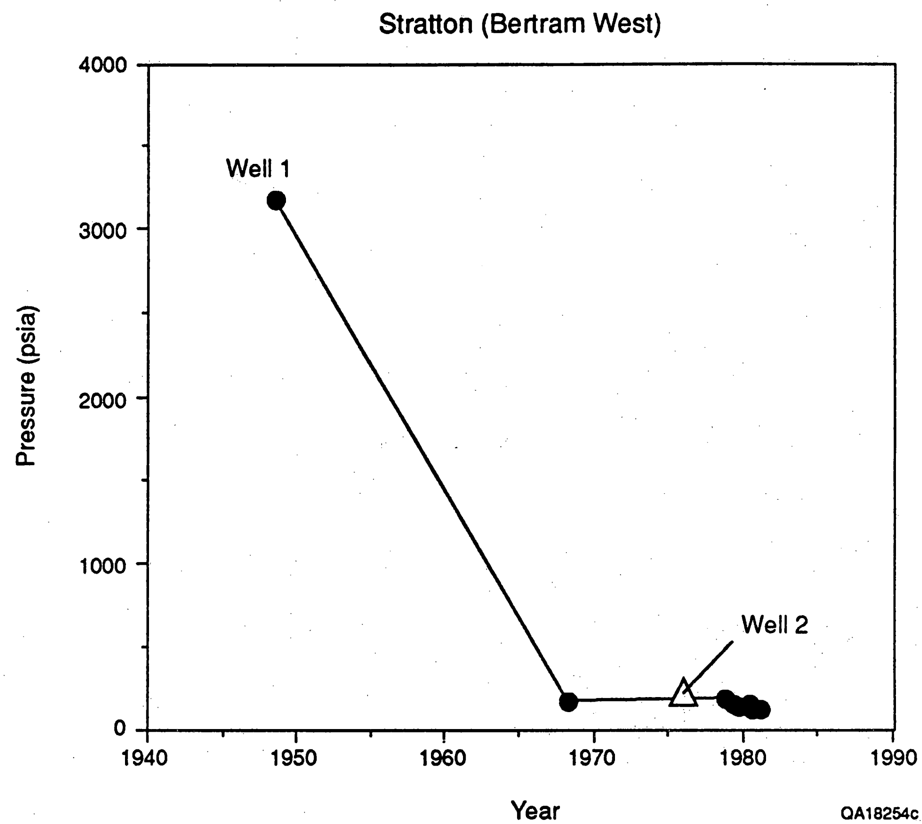

Figure B-1. Cross plot of pressure versus time for completions in the Stratton field, Bertram West reservoir section. Initial pressure of the infill well is less than 500 psi above older completions active at the time of infill.

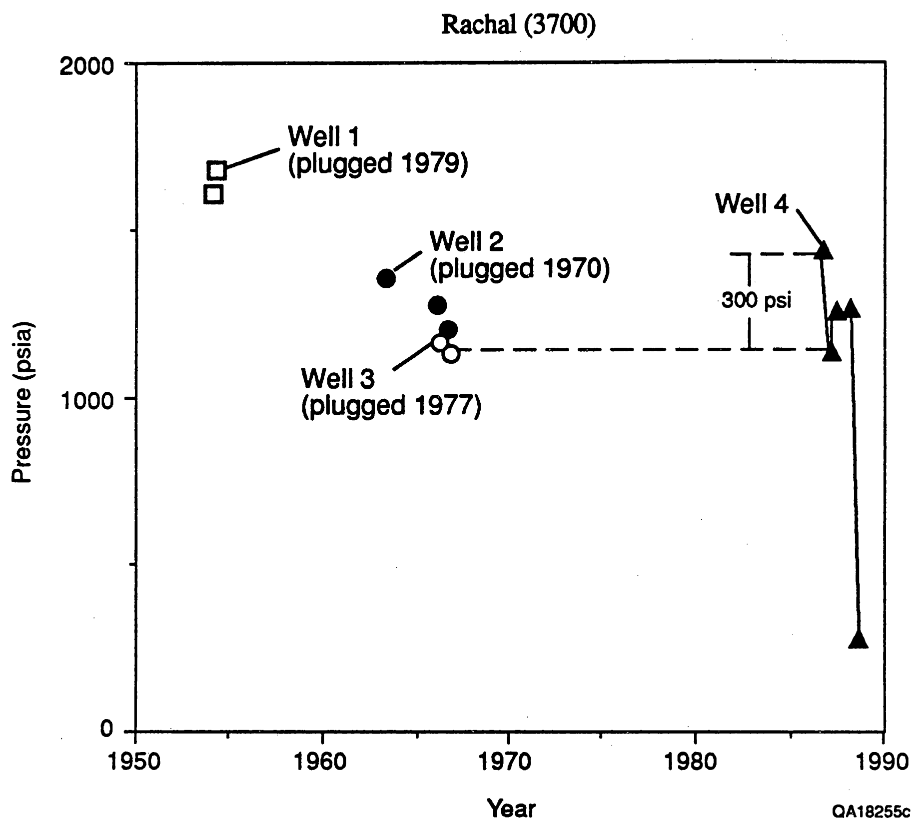

Figure B-2. Cross plot of pressure versus time for completions in the Rachal field, 3700 reservoir section. Initial pressure of the infill well is less than 500 psi above the abandonment pressure of completions which were inactive at the time of infill.

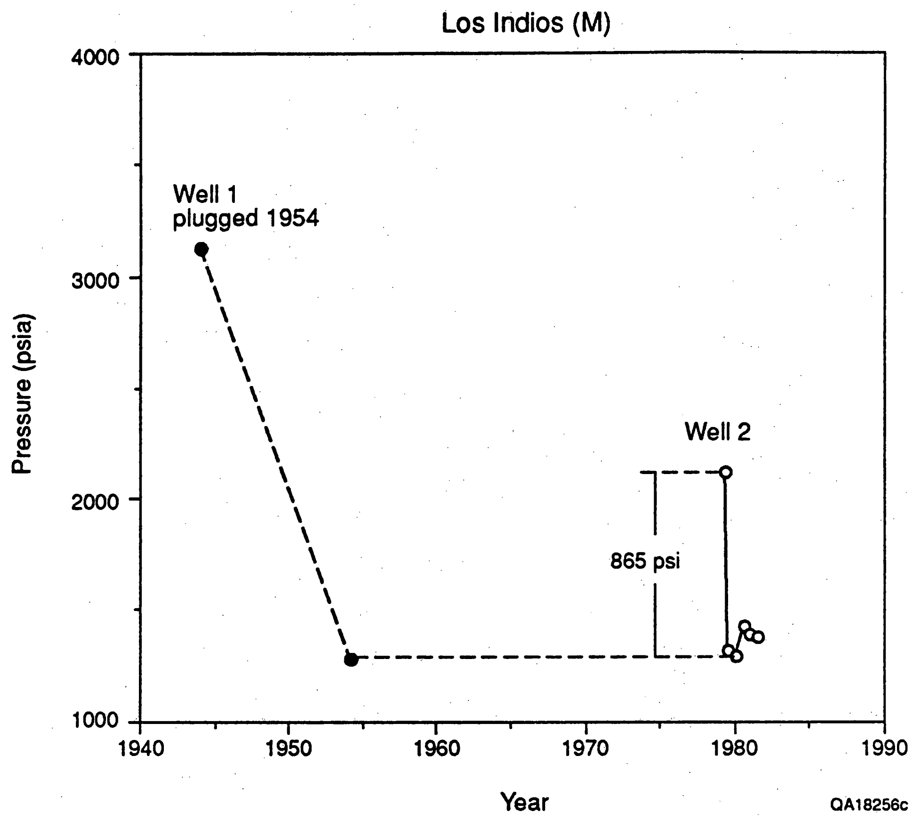

Figure B-3. Cross plot of pressure versus time for completions in the Los Indios field, M reservoir section. Initial pressure of the infill well is greater than 500 psi above the completion pressures of older wells.

Table B-1. Pressure characteristics of Frio same-sandstone reservoir sections with densities from 2 to 4, PPY values >20, and with REUR values in the top 50 percent.

Infill completion pressure characteristics (%)	Reservoir-section field (reservoir)	Density	REUR	Play
≥500 psi above last pressure (33)	Alazan, North (H-36 N)	3	0.252	3
	Candelaria (9600)	3	0.137	3
	Los Indios (G)	2	0.444	4B
	Los Indios (M)	2	0.387	4B
	Magnolia City, N. (3950)	2	0.471	5
	Santa Rosa (10700)	3	0.423	3
	La Blanca (6700 10-A)	2	0.069	2
Abandonment pressure (previous wells inactive) (17)	Mathis, East (Schneider 4600)	2	0.546	8
	Rachal (3700)	4	0.157	4B
	Borregos (Zone R-2 N)	4	0.110	4A
Expected pressure (previous wells active) (50)	Donna (Rice)	2	0.453	2
	Hidalgo (Bell)	2	0.460	2
	Mustang Island (5 7810)	4	0.172	6B
	Pharr (Marks)	3	1.302	6A
	Stratton (Bertram West)	2	0.083	4A
	Stratton (Rivers Upper A)	2	0.071	4A
	Tijerina-Canales-Blucher (Carl)	4	0.313	4A
	Tsesmelis (3400)	4	2.546	5

temperature, production, and pressure characteristics. Permeability, net pay, porosity, water saturation, and temperature were estimated or obtained from Railroad Commission of Texas hearings files. Stratton field parameters were obtained from the SGR project. Pressures and production were not estimated.

Three types of last-completion pressure characteristics were identified: (1) probably in pressure communication with the older well, (2) possibly in pressure communication with the older well, and (3) probably *not* in pressure communication with the older well (fig. B-4). Infill completions determined to be probably in pressure communication with the older well (10 percent of the sample, table B-2) most likely do not represent reserve growth, especially where production continues from other wells in the reservoir section. These completions contact gas at expected pressures—gas already accounted for in previous reserve estimates. Infill completions possibly in pressure communication with the older well (40 percent of the sample) may represent reserve growth, and infill completions probably not in pressure communication with the older well (40 percent of the sample) probably do represent reserve growth.

The results from the two types of pressure analyses were combined. Those reservoir sections where the infill well pressure is in the >500 psi or not connected categories (9 sections) definitely represent reserve growth (9/25, or 36 percent of the sections analyzed), and reservoir sections where the infill well pressure is in the abandonment pressure/previous wells inactive or possibly connected categories (6 sections) possibly represent reserve growth (6/25, or 24 percent of the sections analyzed). Definite and possible reserve growth are demonstrated in 36 percent to 60 percent of the reservoir sections based on the pressure analysis. Single-well pressure testing and multiwell pressure transient testing conducted as part of the SGR project offer the potential to reduce the uncertainty represented by the wide range in these data. Such exclusion of uncertainty was impossible given the scope and quality of the publicly available data base used in this study.

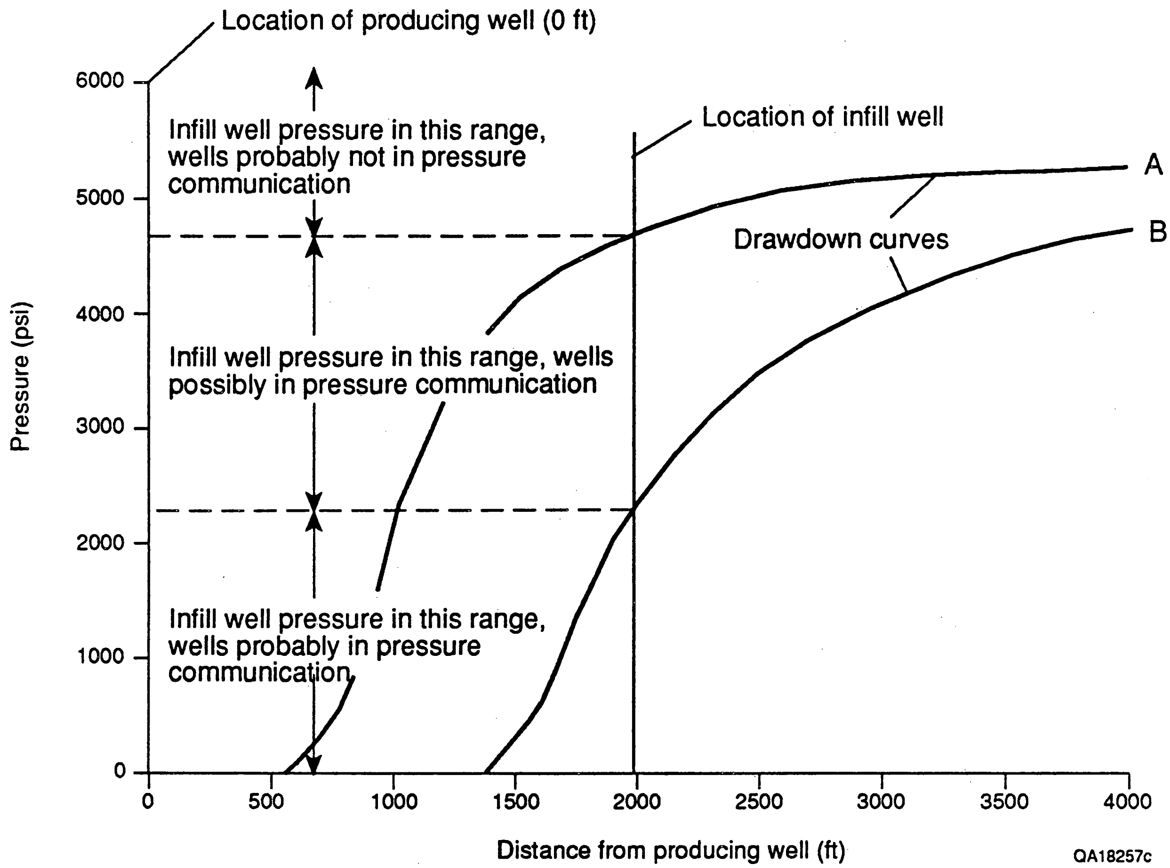

Figure B-4. Pressure drawdown diagram for the two 8,800-ft deep completions in the Monte Christo, North field, F-14-A reservoir section, at normal pressure. Curve A represents the pressure drawdown for a circular reservoir with a radius equal to the distance between the two wells; curve B represents the pressure drawdown for a smaller reservoir with a diameter equal to the distance between the two wells. If the infill completion pressure is below curve B, the two wells are probably in pressure communication. If the infill completion pressure is between curves A and B, the two wells are possibly in pressure communication, and if the infill completion pressure is above curve B, the two wells are probably not in pressure communication. This analysis represents an idealized situation and does not model partial pressure communication between wells, the irregular shapes of Frio reservoirs and resultant drainage areas, or when recharge occurs across flow baffles between compartments.

Table B-2. Types of pressure connectivity between infill completion and previous completion in same-sandstone Frio reservoir sections with densities from 2 to 4, PPY values >20, and REUR values in the top 50 percent.

Reservoir-section field (reservoir)	Density	REUR	PPY	Type of pressure contact between infill completion and previous completion in reservoir section	Play
Los Torritos, N. (Knapp)	2	1.488	29	Not connected	2
Agua Dulce (6600)	2	0.481	30	Not connected	4A
Monte Christo (F-14-A)	3	0.897	44	Not connected	4B
Magnolia City, N. (3950)[1]	2	0.471	23	Not connected	5
Donna (Rice)[1]	2	0.453	23	Possibly connected	2
Stratton(Comstock-B 4700)	2	2.677	27	Possibly connected	4A
Stratton (W-92)	4	0.105	58	Possibly connected	4A
Monte Christo (43)	2	0.597	22	Possibly connected	4B
Agua Dulce (5200)	2	0.642	23	Probably connected	4A
Alice (3400 Frio)	2	0.532	27	Production too low to determine connectivity	5

[1]This reservoir section is also listed in table B-1.

APPENDIX C. FRIO RESERVOIR-SECTION TYPES AND PLAYS.

Table C-1. Reservoir-section types and plays identified in reservoir sections with densities from 2 to 4, PPY values >20, and REUR values in the top 50 percent. CO = consolidated, CY = cycled, D = different-sandstone, FD = faulty data, O = overlapping, S = same-sandstone, WD = water drive, and X = partial section—logs examined but type not determined.

Reservoir-section field (reservoir)	Type	Play*	Density	REUR
ALAZAN, NORTH (I SERIES)	CO	3	4	0.3484
VIBORAS (MASSIVE SECOND)	CY	3	2	0.2762
VIBORAS, WEST (I-57)	CY	3	2	0.2199
VIBORAS (MASSIVE FIRST)	CY	3	3	0.169
CANDELARIA (G-30)	CY	3	4	1.8552
VIBORAS (MASSIVE FIRST)	CY	3	4	2.0723
VIBORAS (MASSIVE FIRST)	CY	3	4	0.3228
VIBORAS (MASSIVE SECOND)	CY	3	4	0.9211
VIBORAS (MASSIVE SECOND)	CY	3	4	0.5427
AGUA DULCE (AUSTIN, MIDDLE EAST)	CY	4A	2	1.0777
AGUA DULCE (5100)	CY	4A	2	0.359
BRAYTON (PERRY)	CY	4A	2	0.5541
LA GLORIA (ARGUELLEZ ZONE)	CY	4A	2	0.124
LA GLORIA (BROOKS)	CY	4A	2	0.0409
LA GLORIA (HAMMOND SOUTH)	CY	4A	2	0.3072
SEELIGSON (ZONE 15)	CY	4A	2	0.0737
LA GLORIA (BROOKS)	CY	4A	3	0.3815
LA GLORIA (ARGUELLEZ ZONE)	CY	4A	3	0.0762
LA GLORIA (BAUMAN SOUTH)	CY	4A	3	0.0832
LA GLORIA (BROOKS)	CY	4A	3	0.111
LA GLORIA (RILEY)	CY	4A	3	0.082
AGUA DULCE (WARDNER)	CY	4A	4	0.2624
AGUA DULCE (5000)	CY	4A	4	0.1959
LA GLORIA (ARGUELLEZ ZONE)	CY	4A	4	0.2106
LA GLORIA (CULPEPPER)	CY	4A	4	0.1174
KELSEY (MCGILL 3 & 4)	CY	4B	2	0.3925
PHARR (MARKS)	D	2	3	1.3023
LOS TORRITOS, NORTH (KNAPP)	D	2	4	1.4047
VIBORAS (ZONE 2)	D	3	2	0.0656
EL PAISTLE, DEEP (FRIO)	D	3	4	0.6096
PITA (E-4)	D	3	4	1.0617
AGUA DULCE (6250)	D	4A	2	0.3211
LOS INDIOS (J)	D	4B	3	0.5878
LOS INDIOS (L)	D	4B	3	1.1435
LOS INDIOS (E)	D	4B	3	0.1323
TABASCO (S)	D	4B	3	0.9642
SCHMIDT (FRIO VICKSBURG)	D	4B	3	0.1482
TABASCO (HEARD SEG 1)	D	4B	4	0.1764
JAY SIMMONS (5850)	D	4B	4	0.2059

Table C-1 (cont.)

Reservoir-section field (reservoir)	Type	Play*	Density	REUR
MUD FLATS (FRIO DEEP)	D	6B	4	1.3732
LA BLANCA (7400 11-A)	FD	2	2	0.1944
LA BLANCA (7750 12-A)	FD	2	2	0.7115
VIBORAS (F-81)	FD	3	3	0.4352
PITA (D-5)	FD	3	4	2.0534
YEARY (STUBBS)	FD	3	4	1.1123
AGUA DULCE (COMSTOCK -A-)	FD	4A	4	0.7946
ROSS, N. (2400)	FD	4B	2	2.2934
KELSEY (K-2, 3 & 4)	FD	4B	3	0.2055
KELSEY, DEEP (FRIO 7250)	FD	4B	4	0.3407
RINCON, NORTH (F-2)	FD	4B	4	0.5976
SARITA, EAST (FRIO)	O	3	4	1.5165
SULLIVAN CITY (GARZA)	O	4B	4	1.0847
LOS TORRITOS, NORTH (KNAPP)	S	2	2	1.4881
DONNA (RICE)	S	2	2	0.4533
LA BLANCA (6700 10-A)	S	2	2	0.0691
HIDALGO (BELL)	S	2	4	0.4602
ALAZAN, NORTH (H-36, N.)	S	3	3	0.2521
CANDELARIA (I-87)	S	3	3	0.1318
CANDELARIA (9600)	S	3	3	0.1374
SANTA ROSA (10700)	S	3	3	0.4227
VIBORAS, WEST (I-33)	S	3	4	0.538
ALICE (3400 FRIO)	S	5	2	0.532
MAGNOLIA CITY, N. (3950)	S	5	2	0.4708
TSESMELIS (3400)	S	5	4	2.5461
MATHIS, EAST (SCHNEIDER 4600)	S	8	2	0.5456
AGUA DULCE (5200)	S	4A	2	0.6423
AGUA DULCE (6600)	S	4A	2	0.481
STRATTON (COMSTOCK-B 4700)	S	4A	2	2.6773
STRATTON (BERTRAM WEST)	S	4A	2	0.0827
STRATTON (RIVERS UPPER A)	S	4A	2	0.0714
AGUA DULCE (COMSTOCK, UPPER)	S	4A	3	0.1177
STRATTON (F-39)	S	4A	3	0.2643
TIJERINA-CANALES-BLUCHER (CARL)	S	4A	4	0.313
BORREGOS (ZONE R-2 N)	S	4A	4	0.1098
STRATTON (W-92)	S	4A	4	0.1051
LOS INDIOS (G)	S	4B	2	0.4443
LOS INDIOS (M)	S	4B	2	0.387
MONTE CHRISTO (43)	S	4B	2	0.5974
MONTE CHRISTO, N. (F-14-A)	S	4B	3	0.897
RACHAL (3700)	S	4B	4	0.1571
PETRONILLA (7500)	S	6A	3	0.2189
MUSTANG ISLAND (5 7810)	S	6B	4	0.1724
ODEM (6850)	WD	7	2	0.7079
PENITAS (5500 MISSION)	WD	4B	3	0.2941

Table C-1 (cont.)

Reservoir-section field (reservoir)	Type	Play*	Density	REUR
WHITE POINT (4900)	WD	6B	2	1.82
SAN MANUEL (8200)	X	3	2	0.3704
BRAYTON (BERTRAM)	X	4B	2	0.7003
GARCIA (VILLAREAL)	X	4B	2	1.0664
DONNA (6600)	X	2	3	0.4158
MERCEDES (3-D)	X	2	4	0.3617
SAN MANUEL (8250)	X	3	3	0.2265
AGUA DULCE (WINFIELD STRAY 6200)	X	4A	4	1.0276
BRAYTON (BERTRAM)	X	4A	4	0.5168
MONTE CHRISTO (57)	X	4B	3	0.2674
RINCON (GAS)	X	4B	3	0.4568
CORTEZ (CORTEZ)	X	4B	3	0.2162
MONTE CHRISTO (25)	X	4B	4	0.5854
BEN BOLT, W. (5400)	X	5	3	0.0835
MAGNOLIA CITY (COOK 5800)	X	5	4	0.2189
TOM GRAHAM (4800)	X	5	4	0.6092
MIDWAY (5300)	X	6B	3	0.3632

*Not all reservoirs are in exact play order.

Table C-2. Summary of reservoir-section types and plays identified in Frio reservoir sections with densities >4, PPY values >20, and REUR values in the top 50 percent. Abbreviations are the same as those in table C-1.

Reservoir-section field (reservoir)	Type	Play	Density	REUR
FLOUR BLUFF (MASSIVE, UPPER)	CO	6A	6	0.5752
FLOUR BLUFF (MASSIVE, UPPER)	CO	6A	7	0.4156
FLOUR BLUFF, EAST DEEP (CONS.)	CO	6A	7	0.1395
ALAZAN, NORTH (J-36)	CY	3	5	0.3836
VIBORAS (MASSIVE SECOND)	CY	3	7	0.0336
BRAYTON (PERRY)	CY	4A	5	0.2515
BRAYTON (SIMMONDS)	CY	4A	5	0.2328
LA GLORIA (ARGUELLEZ ZONE)	CY	4A	5	0.2527
BRAYTON (SIMMONDS)	CY	4A	6	1.694
BRAYTON (SIMMONDS)	CY	4A	7	0.0979
LUBY (C 1)	CY	6A	5	0.9284
YEARY (WALSH)	D	3	6	0.1911
MATHIS, EAST (SINTON 4400)	D	8	5	0.2189
CORPUS CHRISTI, WEST (9800 FRIO)	D	6A	5	0.2953
LUBY (E 1)	D	6A	5	0.2627
CORTEZ (3400)	FD[1]	4B	5	0.5367
AGUA DULCE (5450)	O	4A	7	0.1554
KELSEY (ZONE 14-A)	O	4B	7	0.6588
AGUA DULCE (5450)	S	4A	6	0.2061
MARIPOSA (G- 6)	S	4B	6	0.3384
LAGUNA LARGA (B-1 III)	S	6A	5	2.0541
WHITE POINT, EAST (4000)	WD	6B	7	0.145
HIDALGO (EL TEXANO, UPPER)	X	2	5	0.4951
MERCEDES (1-D)	X	2	5	0.4554
MAY (MASSIVE 2)	X	3	5	0.1777
BRAYTON (6600)	X	4A	5	0.4329
AGUA DULCE (5200)	X	4A	5	0.3684
PREMONT, EAST (17, 4400)	X	4A	6	0.3671
CORTEZ (3400)	X	4B	5	0.5367
TERESA (3110)	X	8	5	0.3827
AMARGOSA (2200)	X	8	7	0.4366

[1]This reservoir section was not in production decline when the last (youngest) infill completion was made in 1964 (fig. C-1).

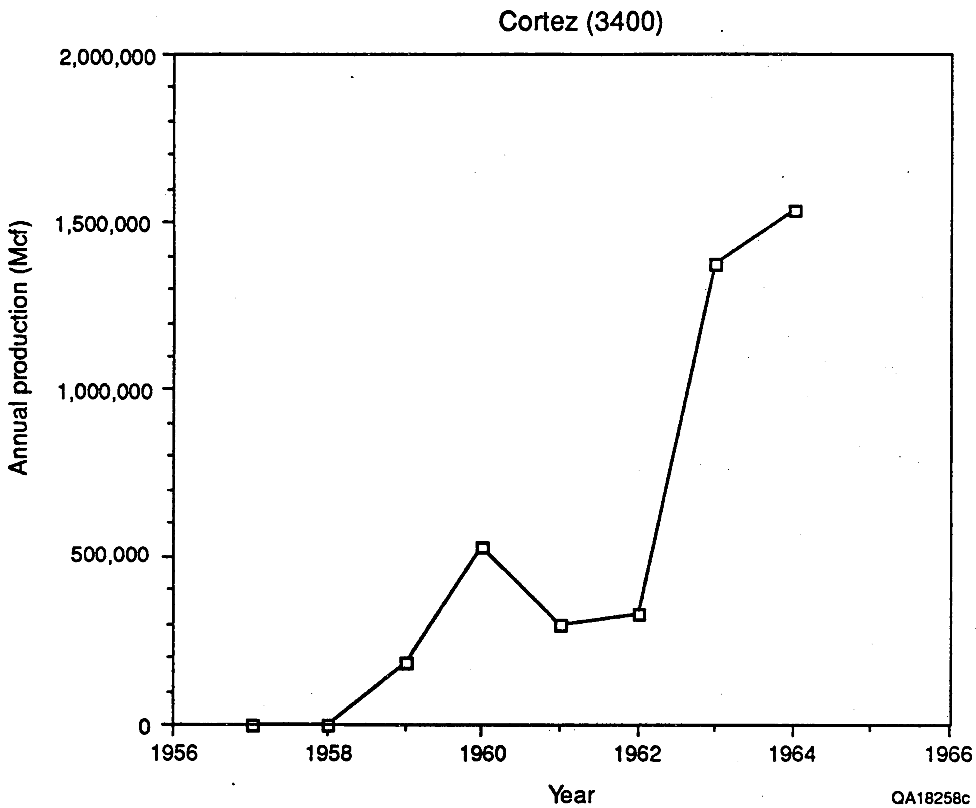

Figure C-1. Annual production in Cortez field, 3400 reservoir, showing that the reservoir was not in decline in 1964 when the last infill well in the reservoir section was completed.

Table C-3. Reservoir-section types and plays identified in reservoir sections with densities from 2 to 4, PPY values >20, and REUR values in the bottom 50 percent. Abbreviations are the same as those in table C-1.

Reservoir-section field (reservoir)	Type	Play	Density	REUR
WHITTED (6000-7000)	CO	2	4	0.0178
FLOUR BLUFF (MASSIVE, UPPER)	CO	6A	3	0.0118
NINE MILE POINT (CONSOL. FLD.)	CO	6B	3	0.0347
MCALLEN (CARD 7100)	CY	2	3	0.1044
VIBORAS (MASSIVE FIRST)	CY	3	2	0.0232
VIBORAS (MASSIVE FIRST)	CY	3	2	0.0243
CANDELARIA (G-63)	CY	3	3	0.0131
VIBORAS (MASSIVE FIRST)	CY	3	3	0.0061
VIBORAS (MASSIVE FIRST)	CY	3	4	0.0859
VIBORAS (03)	CY	3	4	0.0006
VIBORAS (MASSIVE FIRST)	CY	3	4	0.0925
BRAYTON (SIMMONDS)	CY	4A	2	0.0303
BORREGOS (ZONE H-5)	CY	4A	3	0.0074
LA GLORIA (BAUMAN NORTH)	CY	4A	3	0.0486
AGUA DULCE (5000)	CY	4A	4	0.0885
BORREGOS (ZONE P-8, W.)	CY	4A	4	0.0694
LA GLORIA (CULPEPPER)	CY	4A	4	0.0271
KELSEY (MCGILL 3 & 4)	CY	4B	4	0.0006
WESLACO, SOUTH (7400)	D	2	2	0.0138
WESLACO, SOUTH (7400)	D	2	3	0.1318
MCALLEN (HANSEN)	D	2	4	0.008
PHARR (MARKS)	D	2	4	0.0936
LA JARA (FRIO)	D	3	3	0.0131
SARITA, EAST (FRIO)	D	3	4	0.0187
SANTA FE, EAST (MASSIVE 1ST 1)	D	3	4	0.0638
ALICE (3000)	D	5	4	0.0947
SPARTAN (8800 FRIO LOWER)	D	7	2	0.105
STRATTON (F-39)	D	4A	3	0.0126
RICABY (1200)	D	4B	2	0.2476
MONTE CHRISTO, N. (F-17)	D	4B	2	0.0223
SCOTT & HOPPER (6400-C)	D	4B	3	0.0108
SHIELD (7500)	D	6A	3	0.0484
VIBORAS (G-07)	FD	3	4	0.0053
AGUA DULCE (8570)	FD	4A	4	0.111
WEBB (5700)	O	6B	4	0.0341
SAN CARLOS (FF-33)	S	2	2	0.0901
SHEPHERD (JONES)	S	2	3	0.0028
DONNA (JANCIK)	S	2	3	0.0013
LACY (D 7300)	S	2	3	0.0257
SAN CARLOS (FE-81)	S	2	3	0.0095
SAN CARLOS (FF- 2)	S	2	3	0.0589
MARY (FRIO 3400 SALVAGE)	S	5	2	0.1329
ALICE (4500)	S	5	4	0.0479
RIVERSIDE, EAST (2200)	S	7	2	0.0905

Table C-3 (cont.)

Reservoir-section field (reservoir)	Type	Play	Density	REUR
BORREGOS (ZONE H-3)	S	4A	2	0.0005
BORREGOS (ZONE N-8, SW.)	S	4A	2	0.0015
STRATTON (E-25)	S	4A	2	0.0252
STRATTON (F-39)	S	4A	2	0.0065
STRATTON (E-31)	S	4A	3	0.1045
MISSION, WEST (F)	S	4B	2	0.0736
NICHOLS (3100)	S	4B	2	0.0333
MARIPOSA (H-12)	S	4B	2	0.0026
SUN (C-1 FRIO)	S	4B	3	0.1562
LUBY (6100)	S	6A	4	0.0033
FLOUR BLUFF, E. (8700)	S	6A	4	0.055
PETRONILLA (8000)	S	6A	4	0.0603
WEBB (WEBB GAS)	S	6B	4	0.0636
AMARGOSA (2300)	WD	8	4	0.0021
DONNA (ARMSTRONG)	X	2	3	0.0862
DONNA (JANCIK)	X	2	3	0.029
SHEPHERD (MELLINGER)	X	2	4	0.0874
SANTA CRUZ, N. (2450)	X	5	3	0.0846
TOM GRAHAM (3600)	X	5	3	0.0636
MATHIS, EAST (LA ROSA 4700)	X	8	3	0.0021
WADE CITY (3400)	X	8	4	0.1116
RINCON (B-1 FRIO)	X	4B	4	0.12
RINCON, NORTH (A)	X	4B	4	0.0095
CAYO DEL OSO (D)	X	6A	3	0.0068
PETRONILLA (3970 FRIO)	X	6A	4	0.0002
LUBY (5550)	X	6A	4	0.0009
RED FISH BAY (6)	X	6B	3	0.0173

Table C-4. Summary of reservoir-section types and plays identified in Frio reservoir sections with densities >4, PPY values >20, and REUR values in the bottom 50 percent. Abbreviations are the same as those in table C-1.

Reservoir-section field (reservoir)	Type	Play	Density	REUR
ALAZAN, NORTH (I SERIES)	CO	3	6	0.004
FLOUR BLUFF (MASSIVE, UPPER)	CO	6A	6	0.1834
FLOUR BLUFF, EAST DEEP (CONS.)	CO	6A	7	0.0128
FLOUR BLUFF (MASSIVE, UPPER)	CO	6A	8	0.0942
ALAZAN, NORTH (G-91)	CY	3	5	0.0016
JULIAN (22-A)	CY	3	5	0.1768
VIBORAS (MASSIVE FIRST)	CY	3	5	0.1442
VIBORAS (MASSIVE FIRST)	CY	3	7	0.0023
AGUA DULCE (5000)	CY	4A	5	0.318
SANTELLANA, SOUTH (S-2)	D	4B	5	0.0957
ORANGE GROVE (1400)	FD	8	5	0.0356
AGUA DULCE (5450)	O	4A	9	0.0482
TABASCO (O SEG 1)	O	4B	6	0.1896
RIVERSIDE (6900)	S	7	5	0.1537
BALDWIN (8100)	S	6A	5	0.0145
LAGUNA LARGA (B-1 IV)	S	6A	5	0.007
LAGUNA LARGA (C-1, III)	S	6A	5	0.0025
LAGUNA LARGA (C-1, IV)	S	6A	5	0.0081
MIDWAY, S. (COMMONWEALTH)	S	6B	5	0.0855
AMARGOSA (2300)	WD	8	8	0.0008
LUBY (5400)	WD	6A	5	0.0026
HIDALGO (EL TEXANO, UPPER)	X	2	10	0.4459
ORANGE GROVE (1400)	X	8	5	0.0004
AMARGOSA (2200)	X	8	6	0.1599
CERRITOS (8000)	X	4B	5	0.0057
TABASCO (N)	X	4B	5	0.2939
RICABY (1100)	X	4B	8	0.128

Table C-5. Summary of reservoir-section types and plays identified in Frio reservoir sections with densities from 2 to 4 and PPY values from 10 to 20. Abbreviations are the same as those in table C-1.

Reservoir-section field (reservoir)	Type	Play	Density	REUR
STILLMAN (SHALLOW)	CO	3	2	0.0074
FLOUR BLUFF (MASSIVE, UPPER)	CO	6A	3	0.3046
NINE MILE POINT (CONSOL. FLD.)	CO	6B	2	0.134
MCALLEN (CARD 7500)	CY	2	2	0.0558
MCALLEN (CARD 7500)	CY	2	2	0.2589
ALAZAN, NORTH (G-17)	CY	3	3	0.0721
ALAZAN, NORTH (J-36)	CY	3	3	0.0497
AGUA DULCE (PFLUGER, MIDDLE)	CY	4A	2	1.7468
BORREGOS (ZONE P-8, W.)	CY	4A	2	1.6463
BORREGOS (ZONE N-10, E.)	CY	4A	2	0.0267
BRAYTON (SIMMONDS)	CY	4A	2	1.9046
LA GLORIA (JIM WELLS)	CY	4A	2	0.5221
STRATTON (5000)	CY	4A	2	1.4725
AGUA DULCE (BENTONVILLE)	CY	4A	2	0.1731
AGUA DULCE (SPONBERG, SOUTH)	CY	4A	2	0.3019
AGUA DULCE (WARDNER)	CY	4A	2	0.2539
LA GLORIA (BROOKS)	CY	4A	2	0.0118
BORREGOS (ZONE P-8, W.)	CY	4A	3	0.253
BORREGOS (ZONE H-5)	CY	4A	3	0.1734
BRAYTON (SIMMONDS)	CY	4A	3	0.0313
AGUA DULCE (COMSTOCK)	CY	4A	3	0.5663
BRAYTON (PERRY)	CY	4A	4	1.09
ALAMO (7200)	D	2	2	0.1252
HIDALGO (EL TEXANO, UPPER)	D	2	2	0.1202
DINN, SOUTHWEST (FRIO 1500)	D	5	3	1.3068
ODEM (5000)	D	7	2	2.4383
AGUA DULCE (INGRAM)	D	4A	3	1.2059
AGUA DULCE (6100)	D	4A	4	0.0776
KELSEY (ZONE 14-A)	D	4B	2	0.4308
FLOUR BLUFF (FRIO 8300)	D	6A	2	0.0257
STRATTON (E-25)	FD	4A	3	0.4906
STRATTON (E-31)	FD	4A	3	0.2572
RINCON, NORTH (F- 2)	FD	4B	3	0.0945
FLOUR BLUFF (WEBB)	FD	6A	3	0.5609
MCALLEN (HANSEN)	O	2	2	0.1027
MCALLEN (HANSEN)	O	2	2	0.0967
DONNA (KNAPP)	S	2	2	0.1964
LACY (A 7100)	S	2	2	0.1207
LACY (A 7100)	S	2	3	0.1212
CANDELARIA (G-77)	S	3	2	2.6657
MADERO (J-24)	S	3	3	1.926
AGUA DULCE (COMSTOCK, UPPER)	S	4A	2	0.0244
AGUA DULCE (F-22)	S	4A	2	0.7286
BORREGOS (ZONE N-17, C.)	S	4A	2	2.04

Table C-5 (cont.)

Reservoir-section field (reservoir)	Type	Play	Density	REUR
BORREGOS (ZONE H-3)	S	4A	2	1.868
AGUA DULCE (COMSTOCK, UPPER)	S	4A	2	0.0013
ARKANSAS CITY (5600)	S	4B	2	2.7983
CAGE RANCH (6900)	S	4B	2	1.824
KELSEY, DEEP (ZONE 21-I, S)	S	4B	3	1.4907
KELSEY, DEEP (ZONE 19-K,W)	S	4B	4	0.004
COMMONWEALTH (COMMONWEALTH)	S	6B	2	0.6136
FULTON BEACH (A-2)	S	6B	3	0.0356
AMARGOSA (2300)	WD	8	2	1.1792
AMARGOSA (2300)	WD	8	2	0.0232
WHITE POINT, EAST (4000)	WD	6B	3	0.3269
EDINBURG, W. (7600)	X	2	2	0.501
YEARY (MORGAN)	X	3	4	2.3487
AGUA DULCE (COMSTOCK, UPPER)	X	4A	4	2.0987
KELSEY, DEEP (FRIO 7250)	X	4B	3	1.6835
MIDWAY, S. (FRIO DEEP)	X	6B	3	0.1328

Table C-6. Summary of reservoir-section types and plays identified in Frio reservoir sections with densities >4 and PPY values from 10 to 20. Abbreviations are the same as some of those used in table C-1.

Reservoir-section field (reservoir)	Type	Play	Density	REUR
WHITTED (6900)	CO	2	8	0.8889
ALAZAN, NORTH (I SERIES)	CO	3	6	0.926
MADERO (J-24)	D	3	5	0.8968
FULTON BEACH (A-2)	D	6B	5	0.1275
ODEM (5300)	FD	7	5	0.2811
MCALLEN (HANSEN)	X	2	6	0.8651
DOUGHTY (FRIO 9376)	X	6A	5	0.2324

APPENDIX D. VICKSBURG RESERVOIR-SECTION TYPES.

Table D-1. Reservoir-section types identified in reservoir sections with densities from 2 to 4, PPY values >20, and REUR values in the top 50 percent. CO = consolidated, CY = cycled, D = different-sandstone, FD = faulty data, O = overlapping, S = same-sandstone, WD = water drive, and X = partial section—logs examined but type not determined.

Reservoir-section field (reservoir)	Type	Density	REUR
HINDE (VKSBG.)	CO	3	0.3965
LA GLORIA (HORNSBY -C-)	CY	3	0.2172
LA GLORIA (HORNSBY -C-)	CY	4	0.2239
AGUA DULCE (7550)	D	2	0.0468
MCALLEN RANCH (VICKSBURG S)	D	3	0.2436
SCOTT & HOPPER (6800-A)	FD	2	0.4849
LA GLORIA (LOUELLA)	FD	3	1.4968
SEELIGSON (ZONE 21-E WEST)	FD	4	0.2481
ENCINITAS (V-16)	FD	4	0.52
MCALLEN RANCH (VICKSBURG Q)	O	2	1.2607
TIJERINA-CANALES-BLUCHER (10,250)	O	3	0.9223
RINCON, NORTH (VICKSBURG 7600)	O	3	0.5859
MCCOOK, E. (VICKSBURG, LO.)	O	4	0.6488
TIJERINA-CANALES-BLUCHER (10,250)	S	2	2.5245
LA REFORMA (R)	S	2	0.3923
SUN, NORTH (D-4 RES. 3)	S	3	0.1518
MARIPOSA (I-6)	S	3	2.1132
BORREGOS (VICKSBURG)	WD	3	0.8182
MCALLEN RANCH (VICKSBURG-U-V-,SE)	WD	3	1.4336
MCALLEN RANCH (VICKSBURG-U-V-,SE)	WD	4	0.3663
LA REFORMA (R)	X	2	0.1301
SULLIVAN CITY (VICKSBURG, LOWER)	X	3	1.1585
MCALLEN RANCH (VICKSBURG P)	X	3	0.2377
QUINTO CREEK (KOHLER)	X	4	0.9196
LA COPITA (VICKSBURG W)	X	4	0.7529
JEFFRESS (VICKSBURG V)	X	4	0.4651

Table D-2. Summary of reservoir-section types identified in Vicksburg reservoir sections with densities >4, PPY values >20, and REURs in the top 50 percent. O = overlapping and X = partial section—logs examined but type not determined.

Reservoir-section field (reservoir)	Type	Density	REUR
MCALLEN RANCH (VICKSBURG S, SE)	O	5	0.4638
WILLMANN (STILLWELL)	X	5	0.0067
JEFFRESS (VICKSBURG U)	X	5	1.3208
JEFFRESS (VICKSBURG V)	X	5	0.5368
MCALLEN RANCH (VICKSBURG S, N)	X	5	1.0364
MCALLEN RANCH (VICKSBURG S, S)	X	5	0.4949

APPENDIX E. WILCOX RESERVOIR-SECTION TYPES AND PLAYS.

Reservoir-section types and plays identified in reservoir sections with densities from 2 to 4, PPY values >10, and REUR values in the top 50 percent. CO = consolidated, L = Lobo, S = same-sandstone, and X = partial section—logs examined but type not determined.

Reservoir-section field (reservoir)	Type	Play	Density	REUR
LAS TIENDAS (WILCOX)	CO	3	4	0.7979
HUNDIDO (LOBO)	L	2	3	0.6812
LAREDO (LOBO)	L	2	3	2.97
EL GATO (LOBO)	L	2	3	1.2354
LAREDO (LOBO)	L	2	3	2.0886
MUJERES CREEK (LOBO 3)	L	2	3	0.3634
EL GATO (LOBO)	L	2	3	0.905
J. C. MARTIN (LOBO)	L	2	3	0.8673
J. C. MARTIN (LOBO)	L	2	3	0.8673
LAREDO (LOBO)	L	2	3	0.8223
LAREDO (LOBO)	L	2	3	0.6187
LAREDO (LOBO)	L	2	3	0.2853
LAREDO (LOBO)	L	2	4	1.2942
LAREDO (LOBO)	L	2	4	0.9605
LUNDELL (LOBO)	L	2	4	2.1326
J. C. MARTIN (LOBO)	L	2	4	0.557
AGUILARES (ZONE 1)	S	2	2	0.2073
FINLEY-WEBB (WILCOX 5600)	S	3	2	0.3748
D C R 79 (WILCOX)	S	4	2	0.9463
DAVIS, S. (4TH HINNANT)	S	4	4	0.8852
MAGUELLITOS (6500)	X	3	3	1.1362
THOMPSONVILLE, NE (WILCOX 9500)	X	4	3	0.1912
ROLETA (8150)	X	4	4	0.7922
ROSITA, NW. (WILCOX W)	X	4	4	0.5044

APPENDIX F. MIOCENE RESERVOIR-SECTION TYPES AND PLAYS.

Reservoir-section types and plays identified in reservoir sections with densities from 2 to 4, PPY values >20, and REUR values in the top 50 percent. D = different-sandstone, FD = faulty data, S = same-sandstone, WD = water drive, and X = partial section—logs examined but type not determined.

Reservoir-section field (reservoir)	Type	Play	Density	REUR
CLARA DRISCOLL, SOUTH (3800)	D	2	3	0.3274
WHITE POINT, EAST (3700)	D	2	4	0.9259
WADE CITY (2600)	FD	2	3	0.8857
STARR COUNTY, NE. (K-1 GAS 4204)	FD	2	3	0.1656
SAXET (3,100)	FD	2	4	0.9557
SAXET (2,500)	FD	2	4	0.0223
LUBY (3000)	S	2	2	2.0955
ALTA MESA (1100)	S	2	2	2.9333
SINTON, NORTH (1400)	S	2	2	0.2872
SARITA (2-A)	S	2	2	0.4973
PORTILLA (3600)	S	2	3	0.1646
CHAPMAN RANCH (C-16)	S	2	4	0.1678
HOLLY BEACH (LM-4)	WD	1	2	0.2042
HOLLY BEACH (LM-4)	WD	1	2	0.3262
SAXET (2,600)	WD	2	3	0.1597
PLYMOUTH, EAST (5100)	WD	2	4	0.2369
ODEM (3200)	X	2	2	0.7729
ODEM (2160)	X	2	2	0.137
QUINTO CREEK (1900)	X	2	3	0.7794
WHITE POINT, EAST (2300)	X	2	3	0.2275
WHITE POINT, EAST (2940)	X	2	3	0.212
ODEM (3500 SCULL)	X	2	3	0.2379
WHITE POINT, EAST (WHITE PT 2500)	X	2	3	0.168
CLARA DRISCOLL, SOUTH (3800)	X	2	4	2.3903
WHITE POINT, EAST (WHITE PT 3900)	X	2	4	0.4317
ODEM (2000)	X	2	4	0.0583