COORDINATION OF GEOLOGICAL AND ENGINEERING RESEARCH IN SUPPORT OF THE GULF COAST CO-PRODUCTION PROGRAM

FINAL REPORT
(June 1987 - November 1988)

Prepared by

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16. Abstract (Limit: 200 words)

Shallow-marine sandstones in Northeast Hitchcock field having high porosities and permeabilities contain abundant authigenic kaolinite and have acted as preferential conduits for fluid migration. Authigenic clay creates fluid production problems because of its delicate structure. Dislodged clay will obstruct pore throats at high production rates. A maximum safe rate of fluid production will need to be determined for co-produced wells.

Middle and lower Miocene barrier-island sands in Northeast Hitchcock field have the potential for receiving large volumes of co-produced brines. These sands have permeabilities in excess of 2,000 md, are internally homogeneous, and are laterally extensive in the field area.

Detailed geologic analyses of two reservoirs in Seeligson field delineate heterogeneous, fluvial sandstones that probably contain isolated, undrained reservoir compartments. Zone 15 can be subdivided into at least four genetic sandstones, and Zone 18-C can be subdivided into two separate sandstones.

Two new pool discoveries (Miocene) in Tom O'Connor field developed during growth-fault activity along the Vicksburg Fault Zone. Deposition of these sandstones, as part of an offshore system during initial parasequence deposition, was confined between the Vicksburg Fault Zone and the Tom O'Connor anticlinal crest.

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Frio Formation, Northeast Hitchcock field, brine-disposal sands, Seeligson field, Tom O'Connor field

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RESEARCH SUMMARY

Title	Coordination of Geological and Engineering Research in Support of the Gulf Coast Co-Production Program
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5084-212-0924
Principal Investigators	R. J. Finley and D. W. Koppenaal
Report Period	June 1, 1987 - November 30, 1988
Objectives	To investigate the control of depositional environment and diagenetic history on porosity and permeability preservation in the Frio A sandstones, Northeast Hitchcock field.

To select several of the thickest and most laterally continuous Miocene sands in Northeast Hitchcock field for disposal of brines from the Frio A sand. These sands were required collectively to accept approximately 22,000 barrels of brine per day in three disposal wells in Northeast Hitchcock field.

To determine the extent of the main fault block containing Northeast Hitchcock field, thereby defining the maximum area for disposal of brines into these Miocene sands where they have not been offset by major faults.

To determine the lateral extent and thickness of Miocene sands in the fault block containing Northeast Hitchcock field.

To document the brine-disposal potential of Miocene sands in Northeast Hitchcock field and other Miocene sands in nearby fields where large volumes of brines have been disposed.

To select potential sites for brine disposal in Northeast Hitchcock field.

To provide detailed geologic descriptions of cores from three Miocene sands in Northeast Hitchcock field that have a good brine-disposal potential. These descriptions were to be reviewed in conjunction with net-sand and log-facies maps in order that final recommendations could be made for brine-disposal sands in Northeast Hitchcock field.

To establish a cooperative research and development program with industry in order to develop, test, and verify methodologies and technologies with near- to midterm potential for maximizing recovery of gas from conventional reservoirs.

To identify a field for study, develop a cooperative relationship with the operator of the field, and establish a data base from which intensive geological analyses may be built.

To identify compartmentalized and bypassed gas zones in known reservoirs within Seeligson field through detailed log correlations and analysis and interpretation of net-sandstone maps and log-facies maps.

To select wells for recompletion in bypassed or compartmentalized gas zones by integrating cased-hole log evaluation results with advanced geological characterization methods.

To propose recompletion recommendations and present them to the operator, developing recompletion strategies in order to test selected zones.

To investigate the geometry and interpret the depositional setting of lower Miocene sandstones in the Tom O'Connor field area.

Technical Perspectives

Gas and condensate are produced from the Frio A or 9,100-ft sandstone in Northeast Hitchcock field. Investigations were conducted into the structural, stratigraphic, facies, and diagenetic controls of porosity and permeability in the Frio A sandstone. This information defines the size and continuity of Northeast Hitchcock field and problems that may result from high production rates in highly transmissive sandstones.

The best Miocene sands for brine disposal in Northeast Hitchcock field were selected by considering their sand-body complexity, lateral extent, thickness, depth, and documented brine-disposal history, where available. Depositional models, based on core descriptions and interpretation of net-sand and log-facies maps, were constructed for various sands throughout the entire Miocene stratigraphic interval in Northeast Hitchcock field. These models took into account the three important factors of sand-body complexity, lateral extent, and thickness of the sands. Sands having minimal internal complexity and maximum lateral extent and thickness were regarded as the best for brine disposal. Brine-injection data from 43 brine-disposal wells in Hastings West field, located 20 mi from Northeast Hitchcock field in Brazoria County, were compiled in order to determine the brine-disposal capacity of Miocene sands analogous to those in Northeast Hitchcock field, which contained only a few wells that had received brine prior to this study.

Multiple, vertically stacked fluvial to fluvial-deltaic reservoirs are well documented in Seeligson field. The highly complex depositional architecture of these reservoirs provides an excellent setting for evaluation of reservoirs for compartmentalized and bypassed gas zones through advanced geological characterization methods. Delineating genetic sandstone units from aggregate reservoirs through detailed log correlations and interpretation of net-sandstone-isopach and log-facies maps is an integral step in identifying potentially undrained compartments. Two zones were targeted for detailed geologic analysis in Seeligson field, Zone 15 and Zone 18-C. Both zones display characteristics found in fluvial depositional environments of the South Texas Frio. Facies heterogeneities are widespread within each zone and may isolate untapped reservoirs. Cased-hole log evaluation has indicated the presence of gas in each zone in specific wells, and detailed mapping has outlined the extent of the potentially undrained compartments.

Major gas resources have been produced from Miocene sandstones of the onshore Gulf Coast region since discovery and development in the 1930's. Many of these reservoirs are in advanced stages of depletion. New pool discoveries, however, suggest that bypassed or untapped compartments are present in these older fields. Examples are the 4,150- and 4,200-ft sandstones of Tom O'Connor field. Because these sandstones occur near the base of a Gulf-wide progradational event and near a growth-fault zone, the analysis of sand-body geometry and depositional environments is considered in terms of sequence stratigraphy and growth-faulting processes.

Results

At Northeast Hitchcock field the presence of the Skolithos assemblage and other structures has substantiated the interpretation of shallow-marine, tidal, distributary-mouth-bar, and channel depositional environments for most of the major reservoir sandstones. Several shaly horizons have the characteristics of interdistributary bays, and the Frio A is capped by a thin sequence of crevasse splays and washover sands that represent the initiation of the transgression that overlapped the Frio in Anahuac times.

The high-energy depositional environment of reworked distributary-mouth-bar sandstones is the major control of the high porosity (~30 percent) and permeability (~1,000 md) in Frio A sandstones at Northeast Hitchcock field. Well-winnowed sandstones having high porosities and permeabilities contain the most abundant authigenic kaolinite and have acted as preferential conduits for migrating acid waters and for major fluid flow during co-production. Authigenic clay can create fluid production problems because of its delicate structure. Dislodged clay will obstruct pore throats at high production rates. A maximum safe rate of fluid production will need to be determined for co-produced wells.

Middle and lower Miocene barrier-island sands, buried at depths of from 3,500 to 6,800 ft in Northeast Hitchcock field, have the potential for receiving large volumes of co-produced brines from the Frio A reservoir. These sands have high permeabilities in excess of 2,000 md, are internally homogeneous, and are laterally extensive in the field area. The 6,150-ft sand (lower Miocene) was selected for initial brine disposal in the H. D. S. Thompson No. 3 brine-disposal well on the basis of these criteria. The 3,780-ft sand (middle Miocene) is recommended for future up-hole brine disposal in the H. D. S. Thompson No. 3 well because it also is more shallow and therefore requires less injection pressure and less cost for brine disposal.

Detailed geologic analyses of two reservoirs in Seeligson field delineate complex, heterogeneous, fluvial sandstones that probably contain isolated, undrained reservoir compartments. Zone 15, which has been developed under the assumption that it is a homogeneous and continuous reservoir, can be subdivided into at least four individual genetic sandstones within the study area. In many areas, a thin shale bed separates the sandstones, providing a vertical permeability barrier, and facies changes typical of fluvial environments may provide adequate horizontal flow barriers, thereby compartmentalizing reservoirs. Zone 18-C, also developed as a homogeneous and continuous reservoir, is composed of two separate sandstones, one of which had never been tested. Five recompletion recommendations were made for wells in both zones.

Anomalous bottom-hole pressures (BHP) noted in recent Zone 15 completions can be explained through advanced geological characterization methods. Pressures of 1,110 to 1,200 psi recorded in four wells were considerably higher than the expected BHP's of 300 to 500 psi in this "depleted" zone. Detailed depositional-facies maps reveal two major channel complexes separated by floodplain mudstones. Wells with relatively high pressures are located in an untapped channel complex southwest of the floodplain facies, whereas wells with depleted pressures are found in a channel complex to the northeast of the floodplain mudstones.

The 4,150- and 4,200-ft sandstones, new Miocene gas pools of Tom O'Connor field, developed during growth-fault activity along the Vicksburg Fault Zone. Near the fault zone, parasequence gross interval thickness markedly increases, and near the present anticlinal crest, gross interval thickness decreases more than the general, gradual, gulfward decrease in thickness. Log-facies and net-sandstone isopach maps also reflect growth-fault activity. Deposition of the 4,150- and 4,200-ft sandstones, as part of an offshore system during initial parasequence deposition, was confined between the Vicksburg Fault Zone and the Tom O'Connor anticlinal crest. Thus, a complementary anticlinal structure appears to have developed gulfward of the Vicksburg Fault Zone and, in turn, to have influenced the deposition of offshore sands during the initial progradational phase of parasequence deposition.

Technical Approach

A detailed lithologic description was made of the core cut in the Frio A sandstone at the Delee No. 1 well, Northeast Hitchcock field. Relationships were sought between depositional and diagenetic structures and high porosity and permeability. Sandstone petrography was carried out by point counting thin sections made from the Frio A sandstone core.

More than 15 sand beds, 20 to 150 ft thick, were correlated in the entire Miocene stratigraphic interval in 94 well logs, distributed throughout Northeast Hitchcock and Alta Loma fields. Six structural dip sections and one structural strike section were constructed in Northeast Hitchcock and Alta Loma fields. Net-sand and depositional-facies maps based on spontaneous potential (SP) log patterns were constructed for several sand units in Northeast Hitchcock and Alta Loma fields. These maps formed the basis for constructing depositional models of each sand. The best sites for drilling a brine-disposal well in Northeast Hitchcock field were determined by noting the common occurrence of the thickest and most laterally continuous Miocene sands that could be contacted in one well bore. A brine-disposal well, the H. D. S. Thompson No. 3, was drilled in August 1987 in one of these sites. Whole cores were taken of three middle and lower Miocene sands, which have been interpreted as barrier island in origin. Detailed geological descriptions were made of these cores in order to refine previous depositional systems interpretations and to select a sand for initial brine disposal in the H. D. S. Thompson No. 3 well.

Approximately 250 electric logs were correlated in a 9-mi^2 area of Seeligson field in order to define the stratigraphic framework of more than 20 unit reservoirs. A grid of six structural cross sections was constructed to illustrate the lateral extent, thickness, and variability of sandstone reservoirs within the unit. Net-sandstone-isopach and depositional-facies maps were constructed for 30 aggregate zones within the study area. Two zones were selected for detailed geologic evaluation on the basis of sandstone heterogeneity, cased-hole log evaluation results, production histories, bottom-hole pressure characteristics, and the availability of whole core. Highly detailed correlation of SP and resistivity curves identified individual genetic sandstones within each zone, and depositional models for each sandstone were formed by constructing additional net-sandstone-isopach- and log-facies maps. Results from the cased-hole log evaluation project were integrated with advanced geological characterization methods to select wells for recompletion, and recommendations were presented to the unit operator.

In the study of lower Miocene sandstones in the Tom O'Connor field area, a sequence stratigraphic framework was established, and depositional environments were interpreted. The correlation of resistivity markers on wire-line logs served to define parasequence boundaries. Correlation was carried out through a network of cross sections that encompassed about 1,200 mi^2. Log-facies and isopach maps were used to interpret the distribution of depositional environments within the sequence stratigraphic framework.

Project Implications

This final contract report summarizes several phases of work conducted for the Gulf Coast Co-Production Program. The initial focus of the project was geologic characterization of reservoirs being co-produced for water and gas. The focus of the contract then shifted to initial development and testing of methods used to maximize recovery from conventional gas reservoirs in mature fields.

This contract has been completed, but the studies of conventional gas reservoirs that were begun in this contract led directly to the Secondary Gas Recovery Project, which is cooperatively funded by GRI, the U.S. Department of Energy, and the State of Texas. The goal of the Secondary Gas Recovery Project is to develop and demonstrate technologies that will enable producers to better identify and produce natural gas resources that would otherwise remain unrecovered in known fields. Project emphasis will be placed on characterizing and evaluating the internal geometry of gas reservoirs, including the distribution of gas-bearing compartments and of barriers to gas flow.

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by William A. Ambrose

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DEPOSITIONAL ENVIRONMENT AND DIAGENETIC HISTORY OF UPPER FRIO SANDSTONES: CONTROLS ON POROSITY AND PERMEABILITY PRESERVATION IN NORTHEAST HITCHCOCK FIELD, GALVESTON COUNTY, TEXAS

by
M. P. R. Light

INTRODUCTION

Watered-out reservoirs contain substantial quantities of gas that can be produced by the co-production method, which attempts to reduce reservoir pressure through the production of large volumes of water. Free gas, bypassed in the reservoir as it was invaded by the rising gas-water interface, then becomes mobilized and recoverable (Tyler and others, 1987). Additional but minor gas dissolved in formation water also is produced at the surface as pressure is reduced. Thus, watered-out hydropressured gas reservoirs and geopressured prospects can be economically co-produced (Gregory and others, 1983), and watered-out gas reservoirs can become economic sources of natural gas (Dorfman, 1982) in the future.

The co-production potential of Northeast Hitchcock field was analyzed during this project, and the results of investigations into the structural, stratigraphic, facies, and diagenetic controls of porosity and permeability in the Frio A sandstone are presented in this report. This information defines (1) the size and continuity of Northeast Hitchcock field, (2) the source of the high porosity and permeability, and (3) problems that may result from high production rates in highly transmissive sandstones.

REGIONAL BACKGROUND

Northeast Hitchcock field lies 15 mi northwest of the city of Galveston (fig. 1) near the townsites of Hitchcock and La Marque in Galveston County. At Northeast Hitchcock field the Frio A, or 9,100-ft sandstone, is the producing reservoir and is widely dis

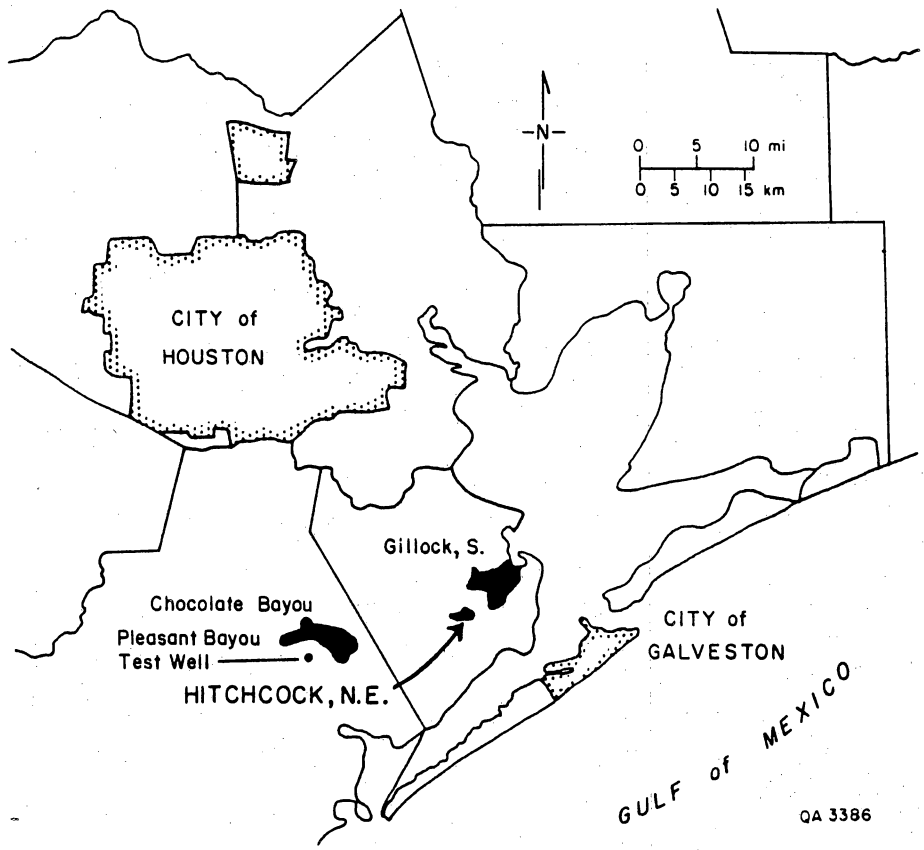

Figure 1. Northeast Hitchcock field location map (modified from Anderson and others, 1985).

tributed in a belt parallel to the Texas coastline. The Frio A is productive in many fields in southern Louisiana and along the Texas Gulf Coast (Anderson and others, 1985).

The T2 marker horizon locally represents the top of the Oligocene Frio Formation and directly overlies the Frio A sandstone reservoir, which, in Northeast Hitchcock field, has an average temperature of 215° F that has a geostatic gradient of 0.6 psi/ft (Light, 1985). The top of the geopressured zone occurs approximately 400 ft below the top of the Anahuac Formation, or 7,200 ft below sea level, in Northeast Hitchcock field (Light, 1985).

The Frio A sandstone in the Northeast Hitchcock area was deposited on the seaward fringe of the Houston delta system (fig. 2) (Light, 1985). (The regional geology has been outlined by Galloway and others [1982]). Several minor, laterally repetitive deltaic cycles comprise the Houston delta system, which is the main locus of terrigenous accumulation in the Frio. Elongate to lobate deltas formed during the most regressive phases in the lower Frio, and more arcuate deltas formed during periods of general transgression and shoreline retreat in the upper Frio (Galloway and others, 1982).

During middle Frio deposition, deltas were supplied by a large fluvial channel system (Chita-Corrigan Fluvial System) 16 to 20 mi north and west of Northeast Hitchcock field. Net-sandstone isopachs show that the position of the fluvial axes changed substantially with time (Galloway and others, 1982). Platform-delta sequences 50 to 300 ft thick characterize the middle and upper Frio in the Houston delta system. Blocky sandstones record the development of multistoried wave-reworked sandstones of recurrent delta-destructional phases—the deltas became smaller as successive lobes shifted landward. Transgression and wave reworking produced thick, time-transgressive blanket sandstones, and there was a constant switching of delta lobes, destructional marine reworking, and inundation of the abandoned sites (Galloway and others, 1982).

The depositional style of the upper Frio was strongly influenced by the Anahuac marine transgression. This shale wedge, which pinches out updip, marks the invasion of a comparatively sediment-starved shelf and contains a neritic fauna. It was partly deposited contemporaneously

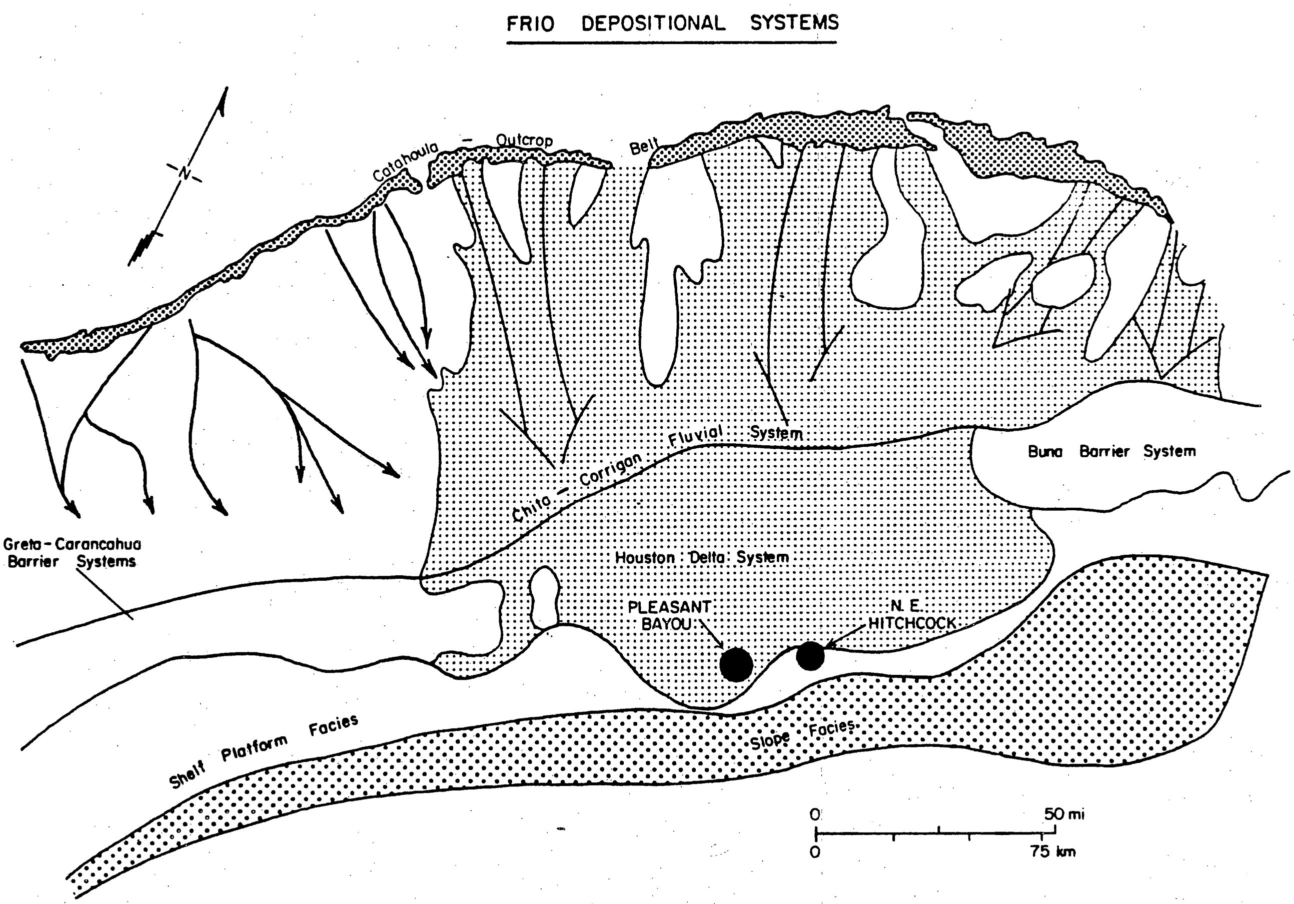

Figure 2. Regional depositional setting of Northeast Hitchcock field, Galveston County, and Pleasant Bayou geopressured-geothermal test wells, Brazoria County, Texas (modified from Galloway and others, 1982).

with, and is hence indistinguishable from, the upper Frio prodelta muds (Galloway and others, 1982).

STRUCTURE

A close pattern of strike-parallel, broadly arcuate fractures was produced by growth faulting during deposition of the Frio (Galloway and others, 1982). In the region around Northeast Hitchcock field, the Frio A sandstone occurs within an ovoid fault block 10.5 mi long and 4.6 mi wide (Light, 1985) in an area characterized by deeply buried salt diapirs (T. E. Ewing, personal communication, 1985). Isolated areas of thick sandstone accumulation may represent sites of major growth faulting or salt-withdrawal basins (Galloway and others, 1982).

Light (1985) has described the detailed structure of Northeast Hitchcock field, which is defined by a northwest plunging anticline of moderate relief truncated on its southeast flank by a major northeast trending growth fault containing several hundred feet of throw (fig. 3). This fault forms the southern boundary of the Frio A reservoir (fig. 3).

A fault wedge upthrown 50 ft comprises the northwest flank of the field and probably formed contemporaneously with Frio A sandstone deposition because there is a marked change in sandstone thickness and facies across the fault. Three other arcuate, northeast trending normal faults dissect the east flank of the reservoir and have throws that vary from 30 to 60 ft (fig. 3). The two western faults appear to have isolated the Cockrell No. 1 Lowell Lemm well from both the Phillips No. 1 Prets well to the west and other wells to the east (Anderson and others, 1985; W. A. Parisi, personal communication, 1984, fig. 3).

A major east-west scissor fault (concave to the north) lies directly south of the Secondary Gas Recovery Delee No. 1 well (fig. 3). Throw on the east-west scissor fault exceeds 100 ft in the west, but its displacement decreases to 30 ft over the crest of the structure. Two other en echelon scissor faults dissect the original Frio A pay zone in the southern part of the Northeast Hitchcock anticline, but the throw on these faults is less than the 50 ft on the western flank of the reservoir (fig. 3). The

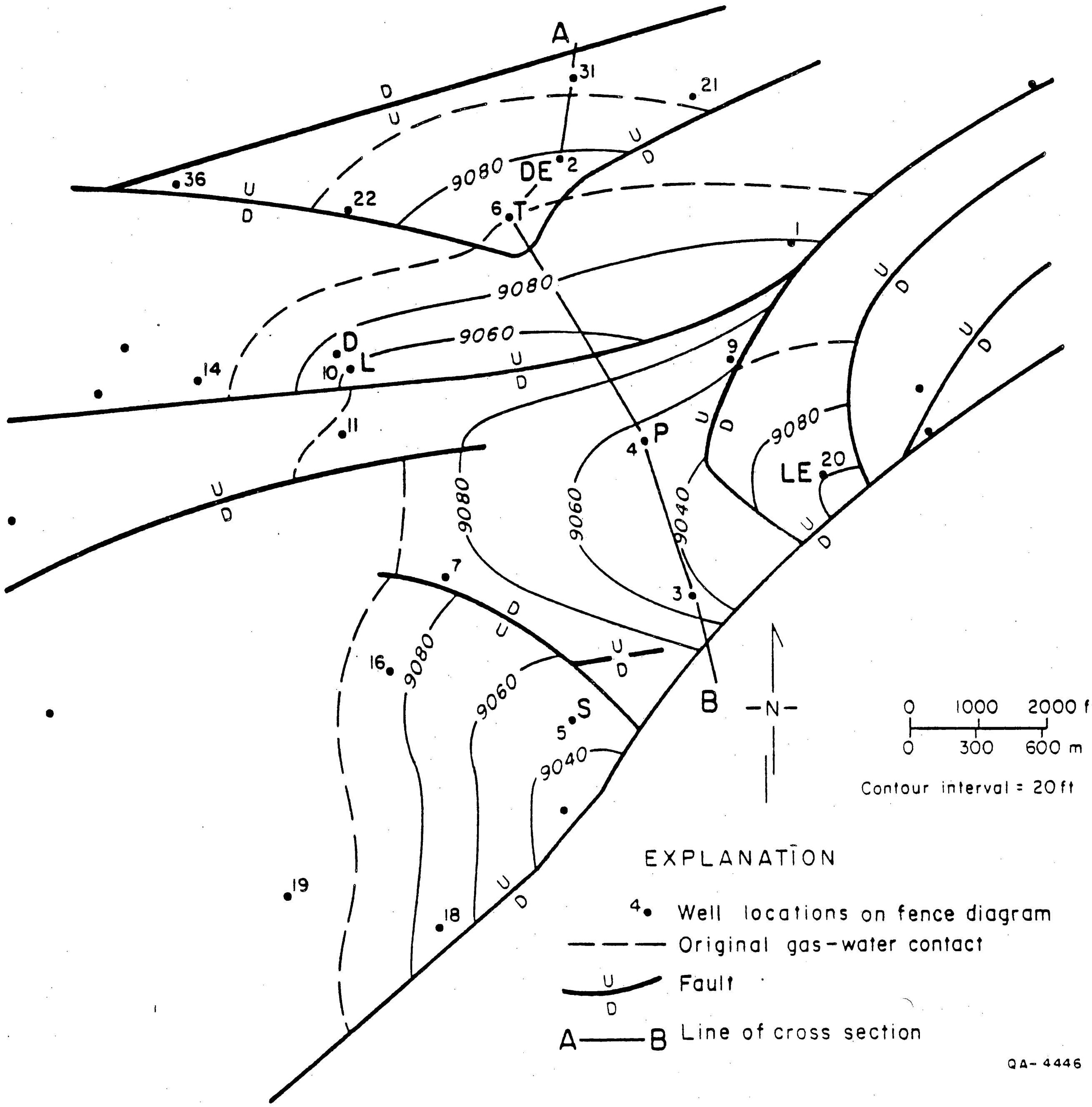

Figure 3. Structure map on top of the Frio A pay zone, Northeast Hitchcock field, Galveston County. Lettered oil well locations are Phillips No. 1 Delaney (DE), Thompson (T), Louise (L), Prets (P), and Sundstrom (S), Secondary Gas Recovery No. 1 Delee (D), and Cockrell No. 1 Lowell Lemm (LE). Cross section A-B is shown in figure 4.

fact that these scissor faults do not disrupt the continuity of the reservoir is evident from the subsurface pressure history. The whole region experienced an almost even pressure drop, from the Phillips No. 1 Delaney in the north to the Phillips No. 1 Sundstrom in the south, over a 24-yr period between 1957 and 1981 (Anderson and others, 1985).

Thin shale breaks appear to stratify the Frio A reservoir and have clearly acted as permeability barriers that trapped liquid hydrocarbons that had formed by retrograde condensation during initial production. Much thicker shale layers are evident on electric logs from the Phillips No. 1 Thompson and Prets wells, and their extent over Northeast Hitchcock field has been defined by Ayers (personal communication, 1986). That minor faults have displaced this local vertical partitioning and isolated parts of the Frio A reservoir is shown by the different oil-gas dew points and oil percentages found in PVT analyses of fluid from the Prets and Thompson wells (Anderson and others, 1985). These shale breaks, having been deposited during periods of quiescence between sand depositions, form vertical barriers separating sandstones. Mapping of fault planes and sandstone lenses has assisted in the identification of isolated sections of the reservoir and can be used to determine the best locations for guard wells for the reduction of water influx (Light, 1985). Furthermore, the location of small sources of trapped free gas in the Northeast Hitchcock field is of great value to field operators completing future co-production wells.

Peterson (personal communication, 1986) mapped four major shale lenses in Northeast Hitchcock field (fig. 4) and demonstrated that the breaks have acted as vertical permeability barriers. Shales have retained small free-gas traps throughout portions of the reservoir, which as a whole has remained fairly homogeneous to pressure and fluid migration (Peterson, personal communication, 1986).

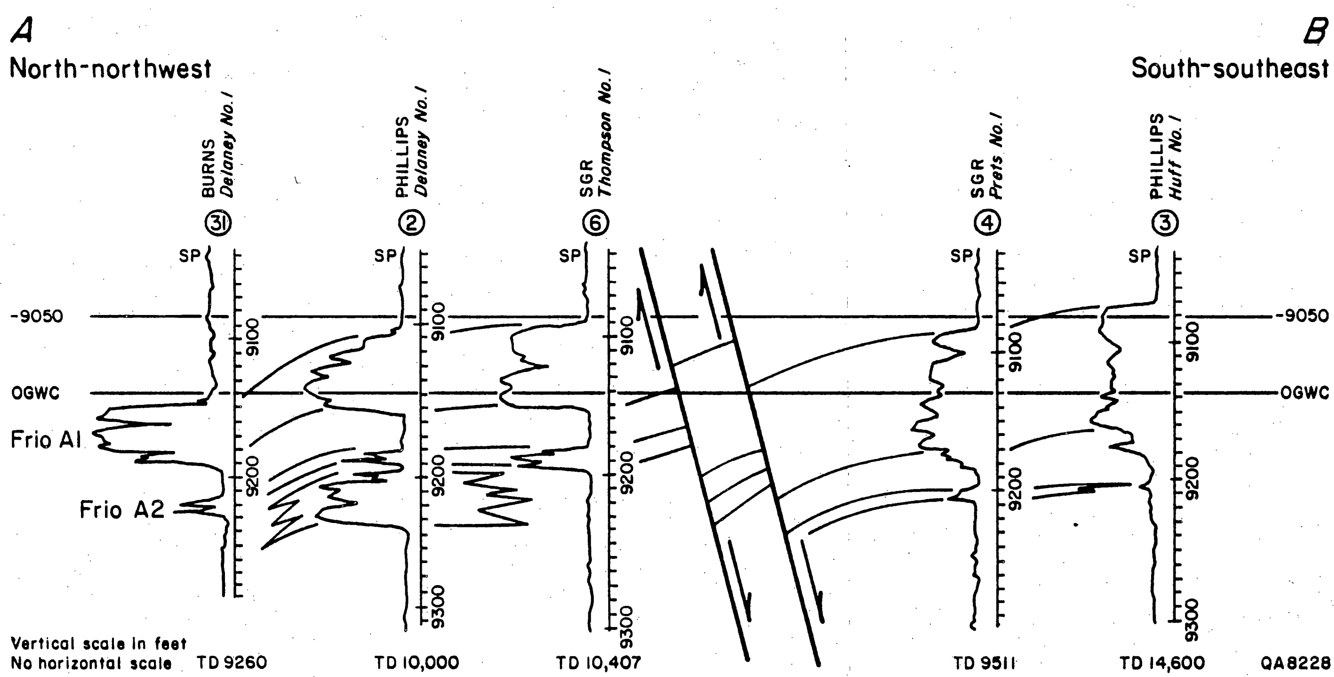

Figure 4. North-south cross section A-B through Northeast Hitchcock field, Galveston County, showing the relationship of the major shale breaks and faults to the original gas-water contact.

STRATIGRAPHY

Regional Depositional Environment

The Frio A sandstone in Northeast Hitchcock field consists of a stacked sequence of distributary-mouth-bar sandstones and thin delta-destructional units that were transgressed by the Anahuac Shale (fig. 5). Regional analysis of the facies distribution of the Frio A sandstone has been conducted using spontaneous potential (SP) profiles, from the Pleasant Bayou test wells in the west (Brazoria County) to Northeast Hitchcock field in the east. In all major sandstone systems in the region there is a transition from thick upward-coarsening sandstones updip to serrate sandstones downdip (fig. 6), and wave-modified sand-rich constructive deltas have produced the characteristic curvilinear strike-parallel distribution of facies (Morton and others, 1983). In Northeast Hitchcock field, the Frio A sandstone shows a well-developed lobate-elongate net-sandstone thickness pattern consistent with deposition in a high-constructive delta (fig. 7) (Light, 1985).

The facies and thickness maps imply that a distributary channel prograded 3 mi southeastward from a fault wedge that forms the northwest flank of Northeast Hitchcock field during deposition of the Frio A sandstone (Light, 1985). This distributary formed a major distributary-mouth-bar deposit on the southern, downthrown block of the fault wedge, and further progradation resulted in deposition of thick sandstones on the downthrown side of the major fault forming the southern boundary of the reservoir (figs. 6 and 7) (Light, 1985). Continuous delta-front sandstones occur in more distal positions, whereas thicker, composite, upward-coarsening SP profiles occur in the southern and eastern part of Northeast Hitchcock field (fig. 6) (Light, 1985). The proximity of the distributary system within the northwest fault wedge is indicated by the SP profiles of the distributary-mouth bars, which are thin and show upward-fining profiles (Light, 1985).

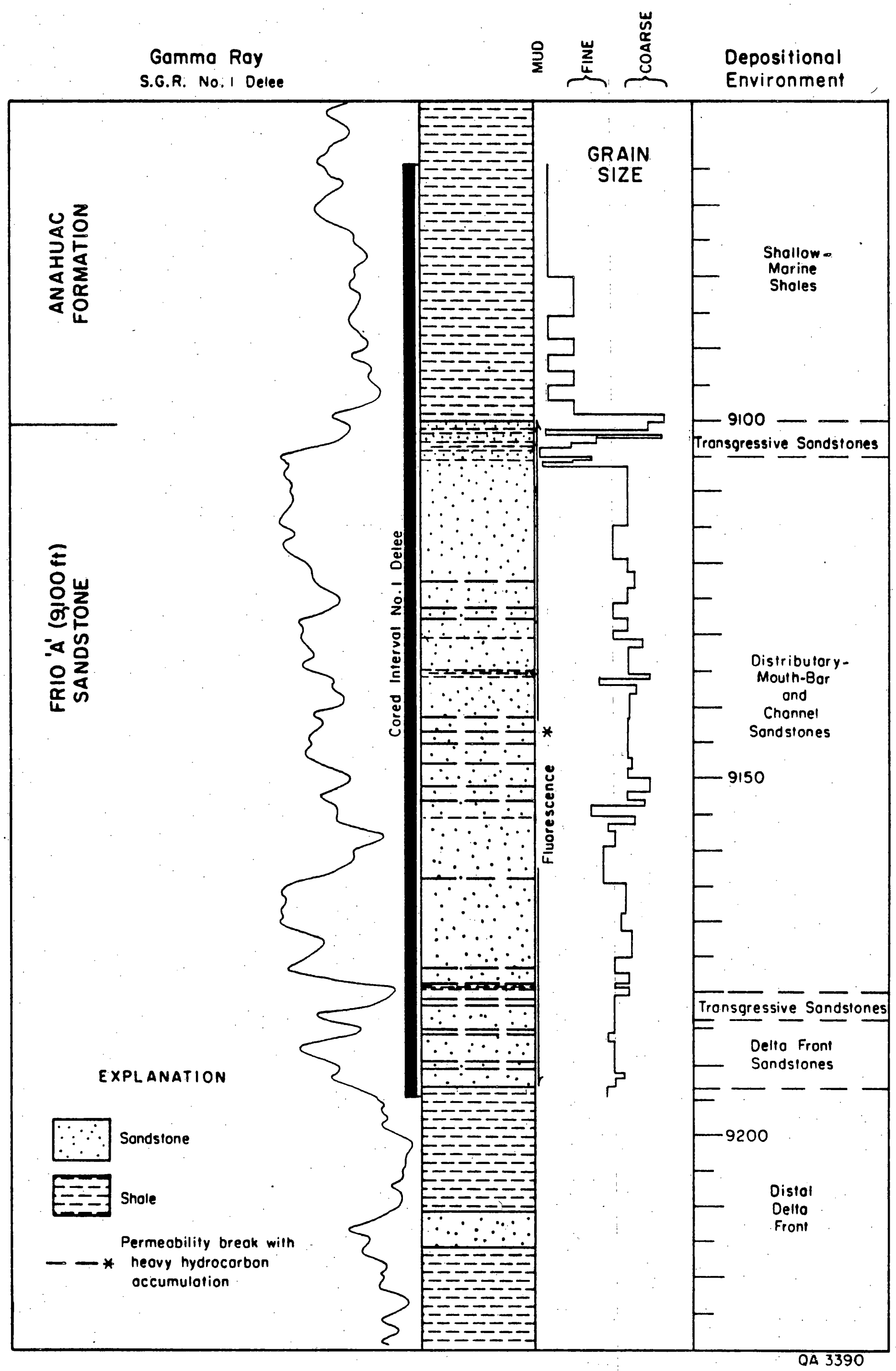

Figure 5. Simplified log of the Frio A sandstone interval in the Secondary Gas Recovery Delee No. 1 well, Northeast Hitchcock field. The gamma-ray response, grain size, and depositional environment are indicated.

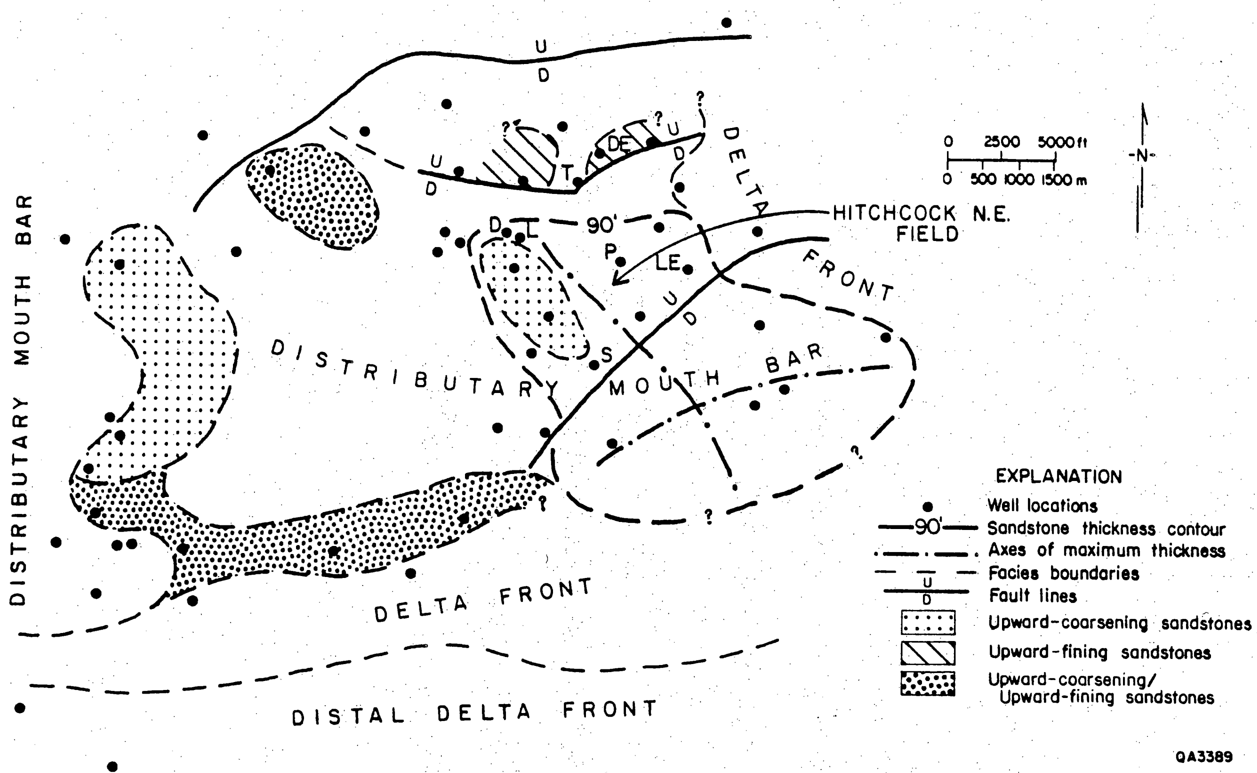

Figure 6. Log-facies map of Northeast Hitchcock field, Galveston County (modified from Noel Tyler, 1984, unpublished work maps).

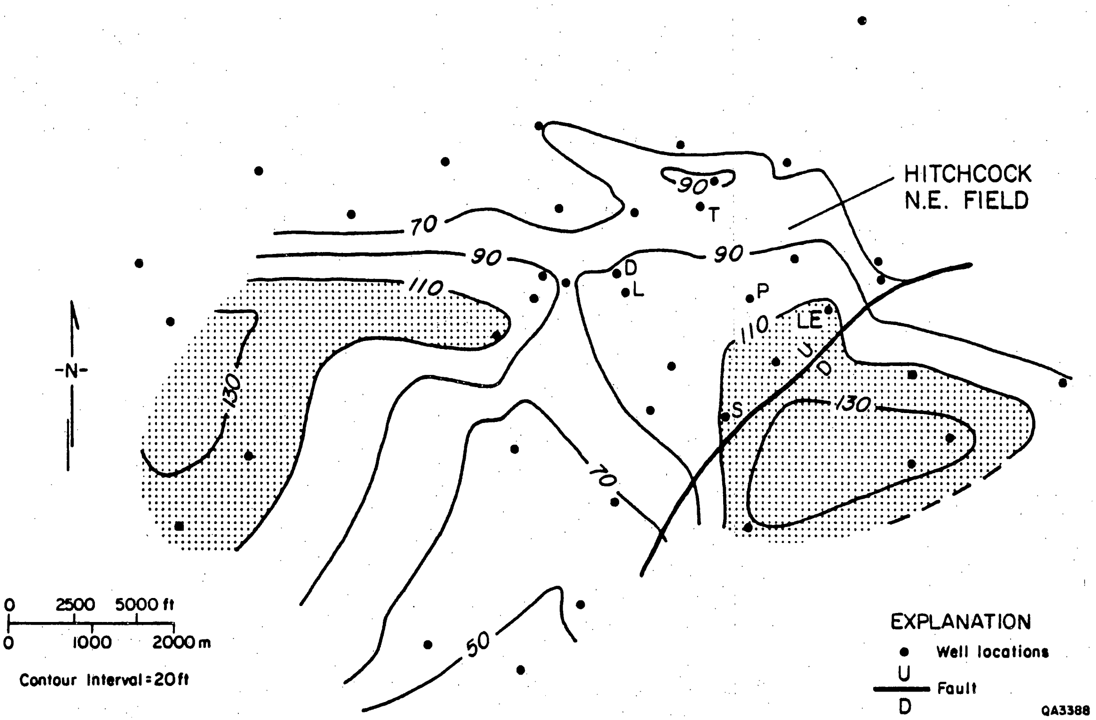

Figure 7. Frio A sandstone-thickness map showing location of Northeast Hitchcock field, Galveston County.

Detailed Facies Interpretations

The Oligocene Frio Formation has been investigated to a depth of 9,402 ft in the Secondary Gas Recovery Delee No. 1 well, Northeast Hitchcock field. Three gas-bearing sandstones were intersected below 9,392 ft, 9,366 ft, and 9,322 ft and were 10 ft, 4 ft, and 28 ft thick, respectively. The thin, light-gray sandstone layers between 9,402 and 9,322 ft consist of subangular, fine to very fine grains that are well-sorted, and moderately cemented. Abundant calcareous material is present, and the presence of glauconite suggests a shallow-marine depositional environment (Selley, 1970). A crude upward-coarsening and increasing-porosity motif shown by rate-of-penetration and SP logs implies that these sandstones were deposited as prograding shoreface marine bars.

Indurated Frio shales in the interval 9,195 to 9,420 ft are dark gray, silty and calcareous. Shales at 9,195 ft, at the base of a 100-ft core cut in the Delee No. 1 well, contain abundant Planolites burrows, common in rocks ranging from the Recent to the Precambrian (Chamberlain, 1978). Planolites are characterized by branched or sparsely branched burrows that are circular, elliptical, or lenticular in section and have unlined distinct walls and poorly defined internal structure (Chamberlain, 1978). The Planolites burrows at 9,195 ft are horizontal, and they occur in clusters and overlap parallel to one another, consistent with an offshore shelf depositional environment.

Frio A Reservoir Sandstones

The Frio A reservoir in the Delee No. 1 well consists of two sandstone units, a lower sand A2 (9,182 to 9,194.1 ft) and an upper sand A1 (9,101 to 9,179 ft), separated by a 3-ft-thick shale break. The lower sand (A1) is 12.1 ft thick, whereas the upper sand (A2) is 78 ft thick. The upper section of the Frio A reservoir was deposited in a transgressive setting and contains three sandy depositional pulses grading up into the Anahuac shelf shales at 9,101 ft.

The lower Frio A2 sandstones consist of an upward-coarsening stack of cross-bedded, light-gray, fine- to medium-grained, sandstone beds 1 to 3 ft thick separated by thin shale breaks. The sandstones are moderately sorted and contain subrounded grains; spotty kaolinite cement occurs near the base above a thin, rippled shale break at 9,191 ft. Sandstones in this interval are indurated by diagenetic cementation. Other shale breaks are calcareous, and an erosional surface occurs at 9,183.5 ft to represent a distributary channel cut into delta-front sands.

The Frio A1, a uniform, fine- to medium-grained, cross-bedded sandstone that is glauconitic and moderately calcareous, forms a 24-ft-thick porous unit from 9,179 to 9,157 ft. It has a sharp basal contact on underlying marine shales. These sandstones are light green or gray green to tan, moderately to well-sorted, and contain rounded to subrounded quartz grains. The 24-ft-thick package of sandstones consists of superimposed smaller crossbedded units 2 to 6.5 ft thick that are highly indurated at the base but less indurated higher up. In the upper part of the package (9,157 to 9,167 ft) the sandstones are more variable in nature, more closely laminated, and are burrowed at various levels.

General Depositional Environment of the Frio A Reservoirs

Coleman and Prior (1980) have described the general sequence characteristic of distributary-mouth-bar deposits. The prodelta section consists of fine-grained clay and silt deposits containing parallel, organic-rich silt layers and distorted laminations alternating with burrowed zones. These grade up into rippled and lenticular-laminated silts and clays representing the distal-bar deposits. Above the distal-bar deposits are distributary-mouth-bar deposits composed entirely of clean, well-sorted sands. Small-scale ripple laminations, current-ripple laminations, and a variety of small-scale cross laminae, low-angle crossbedding, and disturbed laminations occur in these deposits. Mass-movement processes such as small, localized slumps result in distorted laminae. Because of rapid deposition, pore pressures are high within these sands, and a large number of pore fluid-escape structures and localized compactional structures are found in these deposits.

The Frio A sandstones between 9,141 and 9,106 ft have the characteristics of distributary-mouth bars. They are medium grained, moderately to well-sorted, and they contain angular to subrounded grains of quartz, feldspar, and volcanic rock fragments. The higher permeability sandstones are friable and contain thin calcareous streaks and inclined laminations.

The lower permeability parts of the sandstones are similar but show more variability in grain size from fine-grained calcareous sandstones having convoluted bedding to coarse-grained, erosively-based pebbly sandstones. The latter are poorly sorted, have distorted or convoluted bedding, and contain carbonaceous and calcareous shell fragments and shell molds. Thin, dark-gray fissile shale layers occur between sand lobes. The tops of the sandstones are faintly laminated and contain carbonaceous fragments.

Distal-bar deposits have laminated siltstones, silty sandstones, and clays. Distal bars are a highly favorable environment for burrowing organisms, and distal-bar deposits tend to be highly bioturbated (Coleman and Prior, 1980). The decreasing grain size of the glauconitic sandstones between 9,132 and 9,106 ft suggests that these sandstones represent a distributary-mouth bar that was overlapped by distal-bar deposits. Although distal-bar deposits in most progradational sandstones grade from fine to coarse sediments vertically (Coleman and Prior, 1980), the reversed grading seen in these sandstones may result from the distributary-mouth bar retreating (R. A. Morton, personal communication, 1984).

Complete crevasse splay sequences that prograded into an interdistributary bay are represented by two sets of laminated shale, siltstone and sandstone between 9,104.8 and 9,101 ft in the upper part of the Frio A reservoir. Their poorly sorted and conglomeratic nature indicates a fluvial dominance, and the upward-coarsening fabric suggests that they are crevasse splay deposits that breached the fluvial channel and were deposited directly on a washover fan developed on the bayward side of the reworked distributary-mouth bar or levee. This represents the terminal depositional event of the distributary before it was transgressed and buried by the Anahuac Formation shales.

Petrography of Frio A Reservoir Sandstones

The diagenetic sequence and its effect on porosity and permeability preservation in the Frio A sandstone core from the Delee No. 1 well have been studied using 17 thin sections from four depths (9,156 ft, 9,166 ft, 9,177.5 ft to 9,178.5 ft, and 9,189.5 ft). At each level 800 to 1,000 grains were counted, and the average mineral composition and porosity estimated. The sandstones are feldspathic litharenites (Folk, 1974), and numerous diagenetic modifications have occurred in these sandstones as follows: (1) Kaolinite, which postdates quartz overgrowths, has replaced feldspars. (2) Plagioclase and K-feldspar are altered to sericite along cleavages and are rimmed by later kaolinite; late-stage chlorite cement crosscuts kaolinite intergrowths. (3) Sparry calcite rims corroded feldspars, and iron-rich calcite has replaced micaceous minerals.

Hydration of K-feldspar to kaolinite by acid waters prior to the introduction of hydrocarbons has resulted in a porosity increase of as much as 3.5 percent in the well-winnowed distributary-mouth-bar sandstones. Because the conversion of K-feldspar to kaolinite results in a decrease in volume of about 50 percent, the volume of kaolinite is an estimate of the volume of secondary porosity produced by this process.

Porosity in Northeast Hitchcock Field

A direct relationship exists between degree of winnowing (quartz content) and porosity. This relationship is consistent with the wave-reworked nature of the sandstones in the Frio, which formed during recurrent delta-destructional phases (Galloway and others, 1982; Tyler and Han, 1982). The high-energy depositional environment of reworked distributary-mouth-bar sandstones is the major control of the high porosity (~30 percent) and permeability (~1,000 md) in the Frio A sandstones at Northeast Hitchcock field. Although porosity and permeability were subsequently modified by diagenetic reactions, primary porosity was preserved in Frio A reservoirs.

Permeabilities of reservoir sandstones from the S.G.R. Delee No. 1 and Phillips Thompson No. 1 wells, Northeast Hitchcock field, are skewed toward large values, 48 percent of values falling between 1,000 and 3,160 millidarcys (md) (fig. 8). The distribution has a mode of 1,778 md, an arithmetic mean of 1,149 md, and a geometric mean of 693 md. The geometric mean of the permeabilities of producing sandstones at the Delee No. 1 well is even lower (313 md), which suggests that permeabilities in excess of 1,000 md should not be used in reservoir engineering calculations.

Horizontal permeability normally exceeds vertical permeability in the Northeast Hitchcock sandstones, although there is clear linear relationship between them. This is a consequence of the horizontally-bedded nature of the deposits, which have minor horizontal permeability barriers to vertical flow.

Consistent high-permeability and high-porosity values, which vary from 1,134 to 1,493 md and 28.2 to 33.7 percent, are present in the lower Frio A delta-front sandstones between 9,186.2 and 9,192.1 ft (fig. 8). Low-permeability sandstones appear near the top of the stacked distributary-mouth-bar sandstones between 9,155.2 and 9,179 ft. The decreased permeability in these sandstones is probably a result of the increased content of fines in pore throats.

Tidal channel sandstones show the highest permeabilities of all the sandstones, although their porosities (as much as 30.9 percent at 9,149.4 ft) are less than those of the porous distributary-mouth-bar sandstones. Horizontal permeabilities in the tidal channels range from 2,911 md (9,146.3 ft) to 4,446 md (9,152.2 ft). These high permeabilities are evidently the result of winnowing and reworking of these sandstones and the subsequent removal of fine, pore-throat-occluding carbonaceous and shaly material.

Sandstones showing low porosities and permeabilities (158 md and 442 md) occur at 9,125.6 ft and 9,128.6 ft, at the base of a distributary-mouth-bar sequence. The low permeability is directly related to zones of horizontal bioturbation and convoluted laminations. Delta-front slump deposits exhibit a large amount of matrix, which yields a low permeability because of the intermixing of mud and silt by slumping and burrowing (Morton and others, 1983).

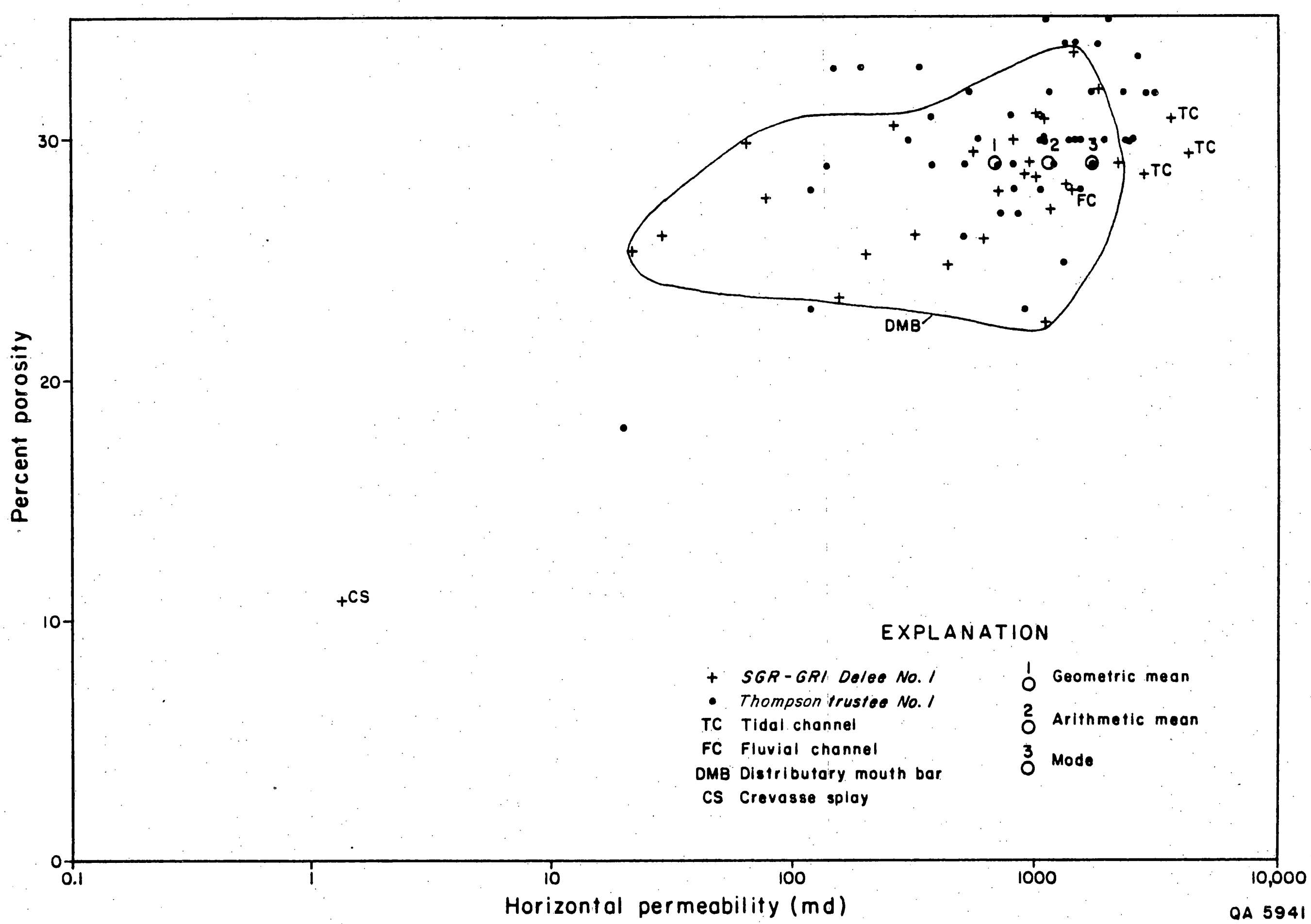

Figure 8. Porosity versus permeability for the Frio A sandstones in Northeast Hitchcock field, Galveston County.

Distributary-mouth-bar sandstones between 9,123.4 and 9,114.8 ft are indurated, kaolinite cemented, noncalcareous and porous at the base but calcareous and friable at the top. High permeabilities are found in the distributary-mouth-bar sandstones at 9,122.3 ft. Evidently excessive winnowing has removed nearly all the fine pore-throat-occluding materials. The permeability decreases upwards, which may result from an increase in the clay content, a result of the distributary-mouth bars retreating (R. A. Morton, personal communication, 1984). Distributary-mouth-bar sandstones between 9,114.8 and 9,105.8 ft also show a decrease in permeability from bottom to top, again a result of the bar sand retreating.

In the transgressive units that form the uppermost part of the Frio A1 reservoir (9,100.6 to 9,101 ft), clusters of <u>Planolites</u> burrows occur in contorted silty and shaly layers. These zones are marked by reduced permeability, which is probably a result of the disruption of the rock fabric caused by the bioturbation.

Blatt and others (1980) have outlined the effect of high clay content on fluid production from reservoir sandstones. In areas of high fluid flow, clays may become dislodged and float through pore channels where they will become lodged in narrow pore throats, greatly reducing the permeability of the sandstone. The pore throats eventually become areas of clay accumulation through which the pore fluid cannot pass. This problem is severe where sandstones contain a high ratio of expandable smectite to other clays because expandable smectite clays are easily dislodged and occupy a greater volume per clay particle. Frio A sandstones with high permeabilities (9,118 ft and 9,122.3 ft) preferentially contain kaolinite, which suggests that kaolinite does not occlude porosity and permeability in the distributary-mouth-bar sandstones. However, because of its very delicate structure, authigenic kaolinite can create fluid production problems at the high production rates (Blatt and others, 1980) that are required when gas and water are co-produced. Safe rates of fluid production that will preserve the high transmissibility of the Frio A sandstones by not causing the migration of clay fines will thus need to be determined.

Shale Dewatering during Production

The potential for the production of shale waters that resulted from major pressure drawdown during co-production of Northeast Hitchcock field has been examined because this is a possible mechanism for reducing the rate of pressure loss. There is little available evidence to demonstrate shale fluid flow (dewatering) during production. Formation water at the Phillips Prets No. 1 well has been analyzed on three occasions over an eight-year period (Kharaka and others, 1977), the more recent analyses being done by the Institute of Gas Technology (IGT) and University of Houston staff (Randolph, 1985b). Although uncertainty exists about the quality of the early analyses and differences in the sampling points and procedures, there has been a slight decrease in chloride-ion concentration of about 5.5 to 8.7 percent that may indicate shale dewatering.

CONCLUSIONS

Depositional environment is the major control of the high porosity in the Frio A sandstones at Northeast Hitchcock field, Galveston County. The high porosity (30 percent) and permeability (1,000 md) of the Frio A reservoir is largely the result of its deposition in a distributary-mouth-bar complex that was subsequently reworked by shallow-marine processes. The wide lateral extent of the Frio A sandstone, which is a consequence of extensive marine reworking, will allow free access to water influx from the southwest extension of this reservoir (Light, 1985).

The best location for guard wells placed below the gas-water contact to control water influx during co-production will be determined by southwest trending fault systems. This is because Northeast Hitchcock field is situated on the northeast flank of the large Frio A reservoir isolated to the north and south by major growth faults (Light, 1985). Minor faults that dissect Northeast Hitchcock field locally isolate parts of the pay zone (Light, 1985) and modify production rates from parts of the field where permeability breaks are present. The best locations for guard wells will also be defined by the position and extent of these zones (Light, 1985).

Carbonate cementation before initial leaching has not been the mechanism through which primary porosity is preserved in the Frio A sandstones. Hydration of potassium feldspar to kaolinite by migrating acidic waters before the introduction of hydrocarbons resulted in a porosity increase of as much as 3.5 percent in the well-winnowed distributary-mouth-bar Frio A sandstones. Because the conversion of potassium feldspar to kaolinite results in a decrease in volume of 50 percent or more, the percentage concentration of kaolinite is a rough estimate of the volume of secondary porosity produced by this process.

Well-winnowed sandstones with high porosities and permeabilities contain the most abundant authigenic kaolinite; these sandstones have acted as preferential conduits for migrating acid waters and for major fluid flow during co-production. Authigenic kaolinite can create fluid production problems because its delicate structure is fragile. In addition, chlorite cement and chlorite rims on quartz overgrowths are present in some sandstones, and these may also be dislodged during high production rates. The dislodged clay and chlorite flakes will obstruct pore throats at high production rates.

A maximum safe rate of fluid production for co-produced wells will need to be determined that will not result in dislodgment and migration of kaolinite, chlorite, and fibrous smectite-illite into pore throats. Experimental flow tests conducted at different flow rates on kaolinite-rich sandstones and measurement of resulting changes in permeability could assist in the determination of the safe upper flow rate.

GEOLOGIC CHARACTERIZATION OF MIOCENE BRINE-DISPOSAL SANDS, NORTHEAST HITCHCOCK FIELD, GALVESTON COUNTY, TEXAS

by

William A. Ambrose

INTRODUCTION

Gulf Coast Co-Production Program

Co-production is a technique designed to improve production from geo- and hydropressured gas reservoirs that have been abandoned or have begun to water out. Wells in watered-out gas reservoirs are usually shut in because of unfavorable economics associated with low gas-production rates and brine-disposal problems.

The Gas Research Institute initiated a series of studies to test the potential for co-production in the Gulf Coast and to dispose of large volumes of associated brines safely and efficiently. This report provides recommendations, on the basis of geologic criteria, for subsurface brine disposal in Northeast Hitchcock field (Galveston County, Texas), where co-production has begun from the watered-out, geopressured Frio A (Oligocene) gas reservoir.

Previous studies funded by the Gas Research Institute (Anderson and others, 1985; Randolph, 1985a; Light, 1985) indicate that large volumes of gas in the Frio A reservoir in Northeast Hitchcock field (Galveston County, Texas) can be economically produced through co-production. However, approximately 22,500 barrels of brine must be disposed of daily, collectively in three wells. The optimum sands for receiving these brines should be: (1) laterally continuous and internally homogeneous, (2) consistently thick throughout the field area, (3) not too deeply buried, and (4) capable of receiving large volumes of brine. Review of these criteria indicates that the best sands in Northeast Hitchcock field for brine disposal are in lower and middle Miocene barrier-island sands, buried at depths of 3,500 to 6,200 ft. These sands have high permeabilities, exceeding 2,000 md, excellent lateral continuity, and internal homogeneity favoring disposal of large volumes of brine. It has been estimated that each of these sands should be capable of receiving 6,000 barrels of brine per day per well, on the basis of analogy to active brine disposal in other Miocene barrier-island sands in nearby fields (Ambrose and Jackson, 1987).

Objectives

Five critical tasks were defined for the selection of the best Miocene brine-disposal sands in Northeast Hitchcock field: (1) determining the extent of the main fault block containing Northeast Hitchcock field, thereby defining the maximum area where Miocene sands have not been offset by major faults; (2) identifying the best Miocene sands for brine disposal by evaluating their internal heterogeneity on the basis of interpretation of net-sand and log-facies maps and core description of the most laterally extensive and thickest sands in Northeast Hitchcock field; (3) documenting the brine-disposal potential of Miocene sands in Northeast Hitchcock field and other Miocene sands in nearby fields where large volumes of brines have been disposed; (4) selecting potential sites for brine disposal in Northeast Hitchcock field on the basis of the common occurrence of the thickest and most laterally continuous portions of potential brine-disposal Miocene sands; (5) describing factors limiting brine-disposal potential of Miocene sands in Northeast Hitchcock field, such as sand-body heterogeneity and calcite cement.

Study Area, Data Base, and Methods

Although Northeast Hitchcock and Alta Loma fields are both located in Galveston County, Texas (fig. 9), Alta Loma field was included in the study because it lies within the same major fault block containing Northeast Hitchcock field. Details of this fault block are illustrated on a structure

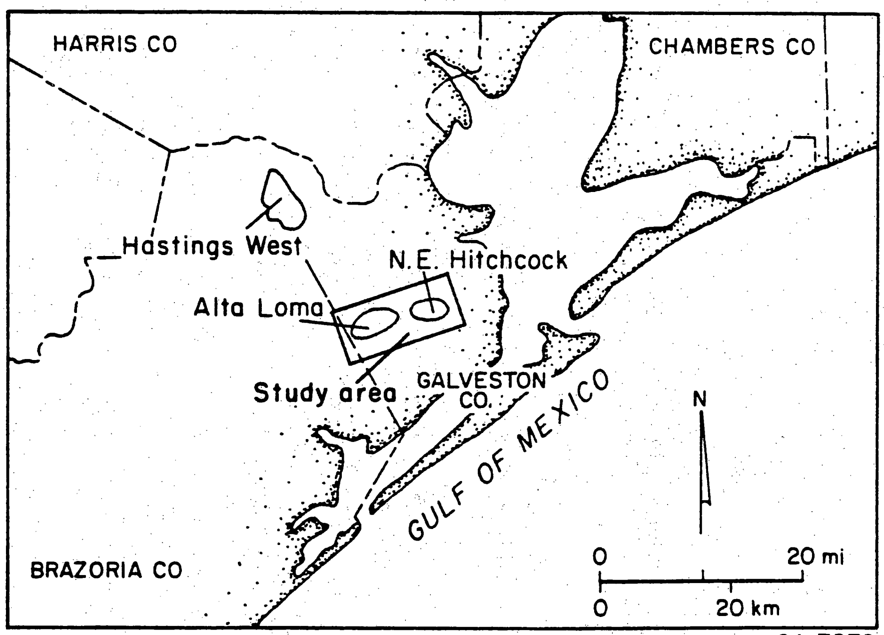

Figure 9. Location of Northeast Hitchcock field, in which several middle and lower Miocene barrier-island sands have been targeted for disposal of brines co-produced with gas from the Frio A reservoir in the field. Hastings West field contained 43 wells in 1985 that were used for brine disposal into Miocene sands analogous to those in Northeast Hitchcock field.

map contoured on the top of the 4,240-ft sand (fig. 10). Two major growth faults that offset Miocene sands from 50 to 200 ft isolate the two fields into a block covering approximately 35 mi^2. Miocene sands in this fault block are offset 40 ft or less by minor faults.

The data base includes 94 well logs distributed throughout Northeast Hitchcock and Alta Loma fields, as well as portions of nearby Franks, Gillock South, Hitchcock, and Sarah White fields (fig. 10). The names of the well logs are listed in table 1.

Brine-disposal histories of Miocene sands in eight of the wells (fig. 10) in the data base were incorporated into the study. Similar but more extensive brine-disposal data from analogous and correlative Miocene sands in Hastings West field (fig. 9) were analyzed in order to determine the brine-disposal potential of other Miocene sands in the region (fig. 11).

Six structural dip sections and one structural strike section were constructed in Northeast Hitchcock and Alta Loma fields (fig. 10) to document the location and offset of the major bounding faults and to determine the lateral extent and thickness of Miocene depositional units to be considered for brine disposal. Net-sand and depositional-facies maps based on SP log patterns were constructed for several lower, middle, and upper Miocene sands in Northeast Hitchcock field (fig. 12). Net-sand thickness was determined from SP logs by using a cutoff line drawn 35 percent of the distance from the SP baseline to a normalized maximum SP deflection for the Miocene in the study area. This value has been successfully used for accurate determination of net sand by the Bureau of Economic Geology in studies of other Tertiary formations in the Texas Gulf Coast (Tyler and Ambrose, 1985).

Depositional facies maps were made of each Miocene sand selected for study on the basis of characteristic SP patterns that were interpreted in conjunction with the net-sand maps. Application of SP patterns to depositional systems interpretation has been effectively demonstrated in previous studies of the Miocene in the Texas Gulf Coast (Morton and others, 1985a) and of other Tertiary units (Galloway and Cheng, 1985; Tyler and Ambrose, 1985).

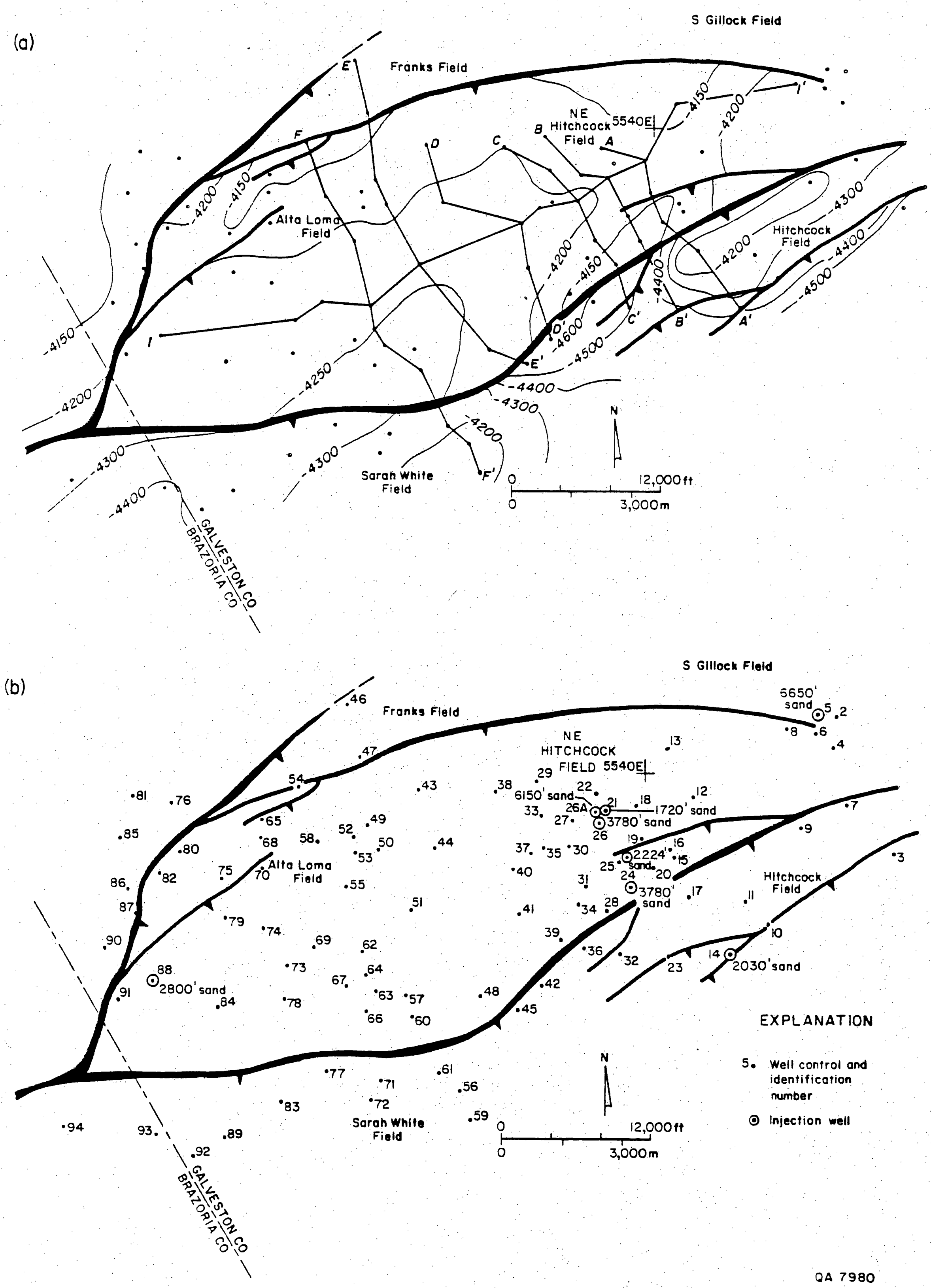

Figure 10. (a) Structure map of Northeast Hitchcock and Alta Loma fields, contoured on top of the 4,240-ft sand (middle Miocene). Two major growth faults, with throws from 50 to 200 ft, isolate these two fields into a 35-mi^2 fault block. (b) Well control used in this study. Miocene sands in six of these wells have received brines; these wells and sands are indicated on the map above. Amounts of disposed brine are indicated on net-sand maps.

Table 1. Well logs used in brine-disposal study of Northeast Hitchcock and Alta Loma Fields.

Well Number	Operator and Lease
1	Pan Am. #1 State Moses Lake
2	Pan American #2 Scofield Comm.
3	Mecom #A-1 Univ. of Texas
4	Pan American #D-4 Kohfeldt
5	Pan Am. #D-3 S. Gillock Un.
6	Pan American #DD-1 S. Gillock
7	Pan American #B-1 S. Gillock
8	Pan American #1-N S. Gillock
9	Mid Sts. #1 Westbridge Un.
10	Cockburn #1 Dobbs, et al.
11	Hanson #2 Title and Guar.
12	Total Pet. #1 Stuart
13	Pan American #1 Bogatto Comm.
14	Cockburn #1 Aarco
15	Sue-Ann #1 Dynamic Land Devel.
16	L.B. Wright #1 Schaub
17	Adobe & Cameron #1 Stubbs
18	Phillips #1-A Fox
19	Phillips #1-D Davis
20	Cockrell #1 Lemm
21	Phillips #1 Delaney
22	R.L. Burns #1 Delaney
23	Humble #1 Coon Fee
24	Phillips #1-A Huff
25	Phillips #1 Prets
26	Phillips #1 Thompson
26A	H.D.S. #3 Thompson
27	Kennedy and Mitchell #1 Delaney
28	Phillips #1 Sundstrom
29	Placid #1 Weidman
30	Phillips #1-A Louise
31	Mecom #1 Kipfer
32	Tx. E. Trans. #1 Hitchcock G.U.
33	Mecom #1 Wittgen
34	Phillips #1 Lasalo
35	J.S. Michael #1 Newman
36	Slater et al. #1 Flake G.U.
37	Kimball #1 Knox est.
38	Placid #1 Camp Wallace G.U.
39	Slater et al. #1 Delasandre
40	H&M Gas and Oil #1 Reichmeyer
41	Aikman Pet. #1 Drew Unit
42	Tx. E. Trans. #1 White G.U. 4

Well Number	Operator and Lease
43	Placid #1 Lobit
44	Hassie Hunt #1-A Ghino
45	Tx. E. Trans. #1 White G.U. 3
46	Placid #1 Thompson G.U. 1
47	Placid #1 Crane G.U.
48	Tx. E. Trans. #1 Henck
49	Hassie Hunt #1 S.H. Green
50	Hassie Hunt #3 S.H. Green
51	Hassie Hunt #1-A Brister
52	Hassie Hunt #1 H. Sealy
53	Hassie Hunt #1 M. David
54	Hassie Hunt #1 Nelson
55	Hassie Hunt #1 R.B. Wilkins
56	Gulf #2 Emil Firth est.
57	Phillips #1-A Tacquard
58	Hassie Hunt #1 M. Rogers
59	Alamo Pet. #1 Firth est.
60	Damson #1 G. Latimer
61	Gulf #1 Lowenstein
62	Phillips #1 O'Daniel Un.
63	Phillips #2 O'Daniel Un.
64	Phillips #3-A O'Daniel Un.
65	Hassie Hunt #1 Sayko
66	Phillips #1-A Evans
67	Phillips #1 McVea
68	Hassie Hunt #2 Sayko
69	Hassie Hunt #1 M. Jensen
70	Phillips #2-B Pabst
71	Tx. E. Trans. #4 Craig
72	Tx. E. Trans. #3 Craig
73	Phillips #1 Lauzon
74	Jolensky-Gideon #1 Tacquard
75	Phillips #1-B Pabst
76	Reb. Pet. #1 Chapman
77	Mecom #1 Roos Trustee
78	Phillips #A-1 Christensen
79	Crystal Oil #1 McIlvane
80	Del Mar #1 W.N. Zinn
81	M.P.S. Prod. #1 Chapman
82	Del Mar #1 Harris
83	Tx. E. Trans. #1 Halls Bayou R.
84	Buttes #1 Sun Amoco Fee
85	The Texas Co. #1 Joe Tucker
86	The Texas Co. #B-1 J.W. Harris
87	Tx. E. Trans. #1 Newton
88	Gen. Crude #1 Reitmeyer-Briscoe

Well Number	Operator and Lease
89	Edwin Cox #1 Halls Bayou Ranch
90	Tx. E. Trans. #1 Nana
91	Pan American #1 R.E. Brading
92	Buttes #2 A.B. Marshall
93	Fina, et al. #1 Marshall
94	Phillips #1 McIlvane

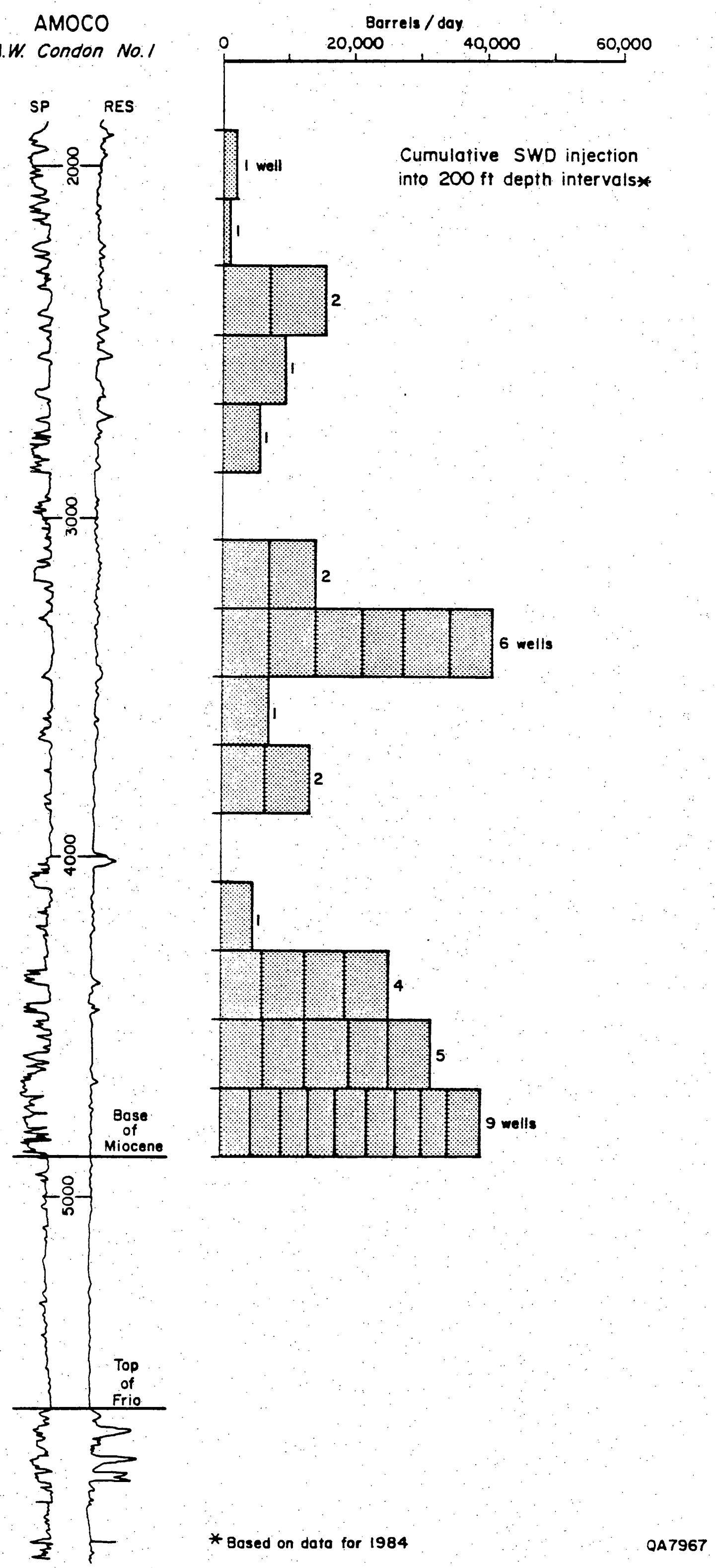

Figure 11. Type log in Hastings West field, located 15 mi northwest of Northeast Hitchcock field. Barrier-island and wave-dominated deltaic sands received 242,000 barrels of brine per day in 1985 from 43 wells in Hastings West field. Lower Miocene sheet sands in Hastings West field are capable of receiving 10,000 barrels of brine per day per well. Figures obtained from the Railroad Commission of Texas.

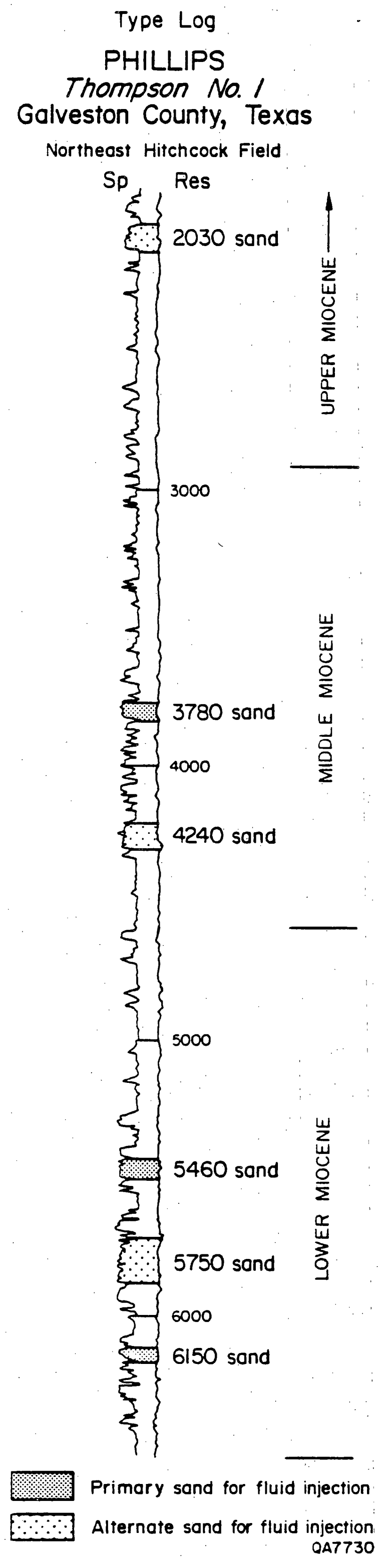

Figure 12. Type log (Phillips Thompson No. 1; number 26 in this study) in Northeast Hitchcock field. The three best zones for brine disposal (3,780 ft, 5,460 ft, and 6,150 ft) are in barrier-island depositional units that contain large volumes of homogeneous barrier-core facies. Three alternate sands (2,030 ft, 4,240 ft, and 5,750 ft) are also shown.

PREVIOUS WORK

In 1987 the Bureau of Economic Geology provided recommendations for the best Miocene brine-disposal sands in Northeast Hitchcock field on the basis of a study of depositional architecture and brine-disposal history of Miocene sands in the region. These recommendations were summarized in a report by Tyler and others (1987) that also furnished a review of Miocene depositional systems in the region, as well as a discussion of important geologic criteria (sand-body geometry, sand thickness and depth of burial, and brine-disposal history) for selection of good brine-disposal sands. Tyler and others (1987) used these criteria to recommend potential sites in Northeast Hitchcock field for brine disposal into three Miocene sands, the 3,780 ft (fig. 13), 4,240 ft (fig. 14), and 5,460 ft (fig. 15). These sands were chosen because they are thick, relatively simple barrier-island sand bodies that contain only minor interbedded mud. The best brine-disposal site in Northeast Hitchcock field was selected by notation of the common occurrence of the thickest and most laterally continuous portions of these three sands that could be contacted in one well bore. Potential pore volumes available for brine disposal in these sands in the fault block that contains Northeast Hitchcock and Alta Loma fields were calculated from net-sand maps and porosity values of each of these three sands and three alternate sands (table 2). Porosity values for the sands were derived from previous studies of the shallow Miocene in the Texas Gulf Coast (Doyle, 1979; Galloway and others, 1986).

Three alternate Miocene sands were also designated by Tyler and others (1987) for brine disposal in Northeast Hitchcock field, the 2,030-ft, 5,750-ft, and 6,150-ft sands. Although these sands were considered good alternates, they also contain various attributes that may limit their potential for brine disposal. For example, the 2,030-ft sand (fig. 16) is attractive as a brine-disposal sand because it has a maximum thickness of 75 ft and is not deeply buried in Northeast Hitchcock field. Nevertheless, it has a complex internal geometry, consisting of several lenticular, laterally discontinuous distributary sands separated by delta-plain mud. The 5,750-ft sand (fig. 17) is a thick barrier-island sand that has a strike-parallel geometry similar to that of the 3,780-ft and 5,460-ft

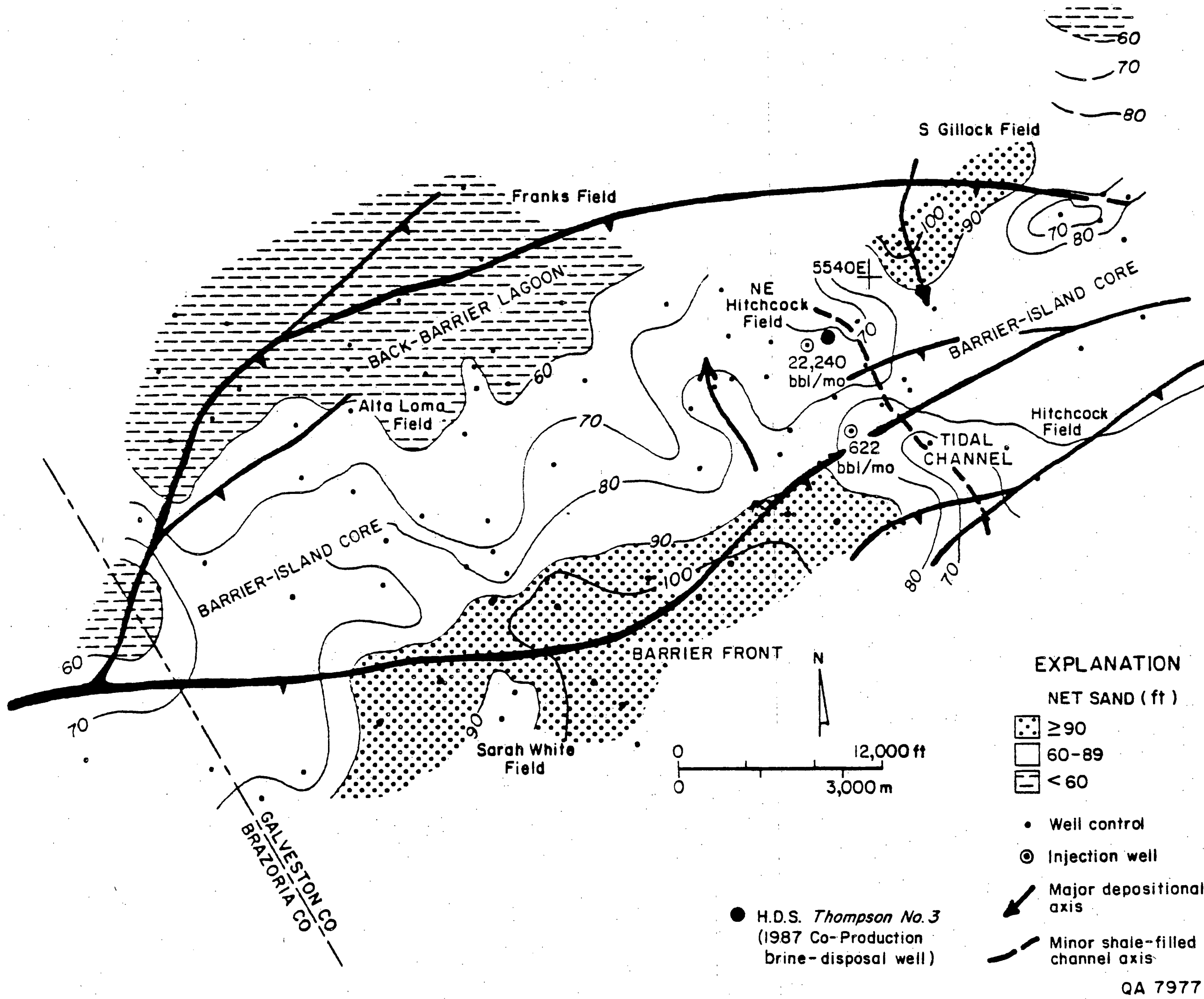

Figure 13. Net-sand and depositional-facies map of the 3,780-ft sand (middle Miocene). This barrier-island sheet sand contains large volumes of homogeneous barrier-core deposits and is therefore an excellent choice for future up-hole brine disposal in Northeast Hitchcock field.

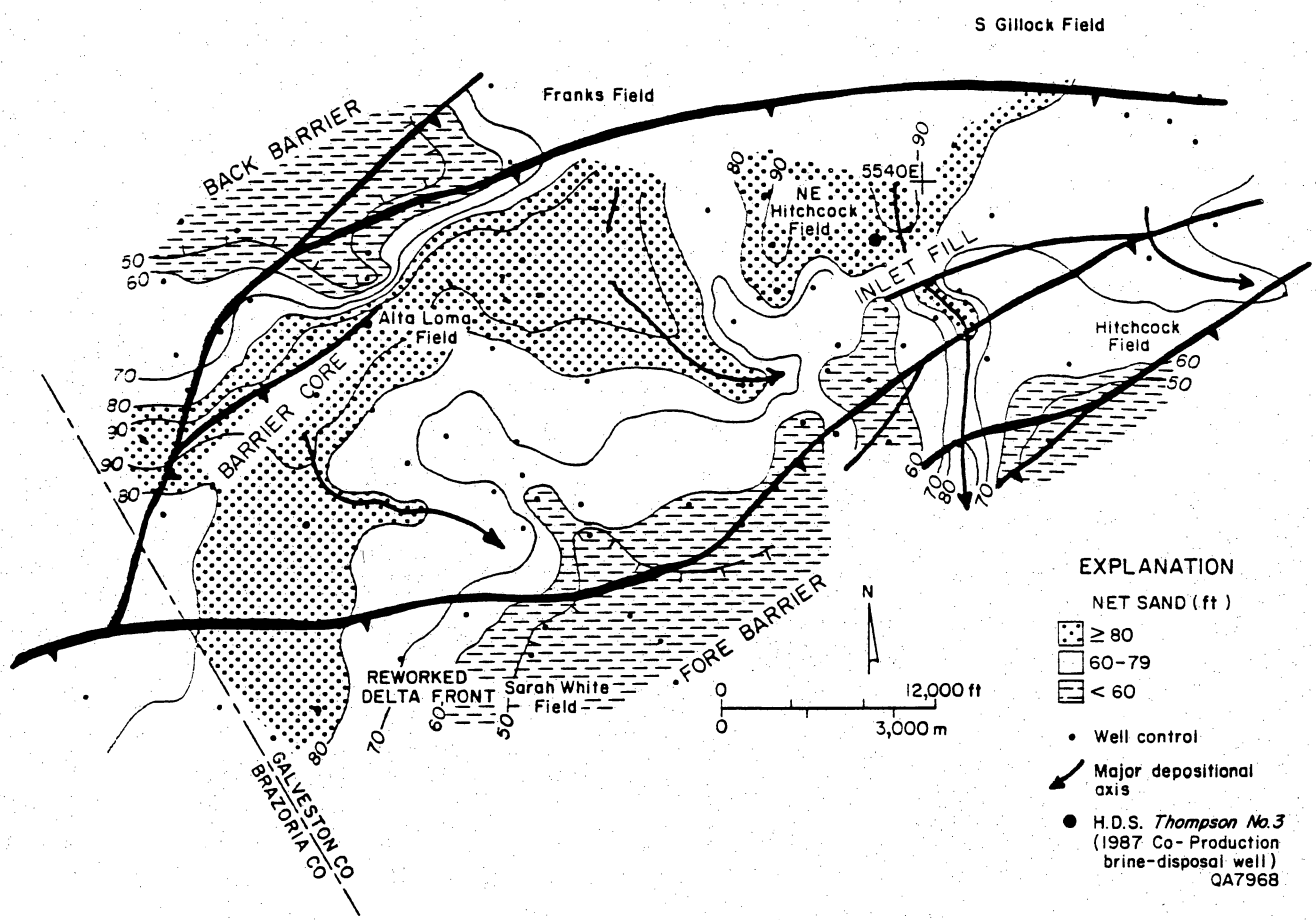

Figure 14. Net-sand and depositional-facies map of the 4,240-ft sand (middle Miocene). This barrier-island sand contains large volumes of tidal-inlet deposits that interrupt sand-body continuity along the axis of the barrier system. These tidal-inlet deposits reduce the net brine-disposal potential of the 4,240-ft sand.

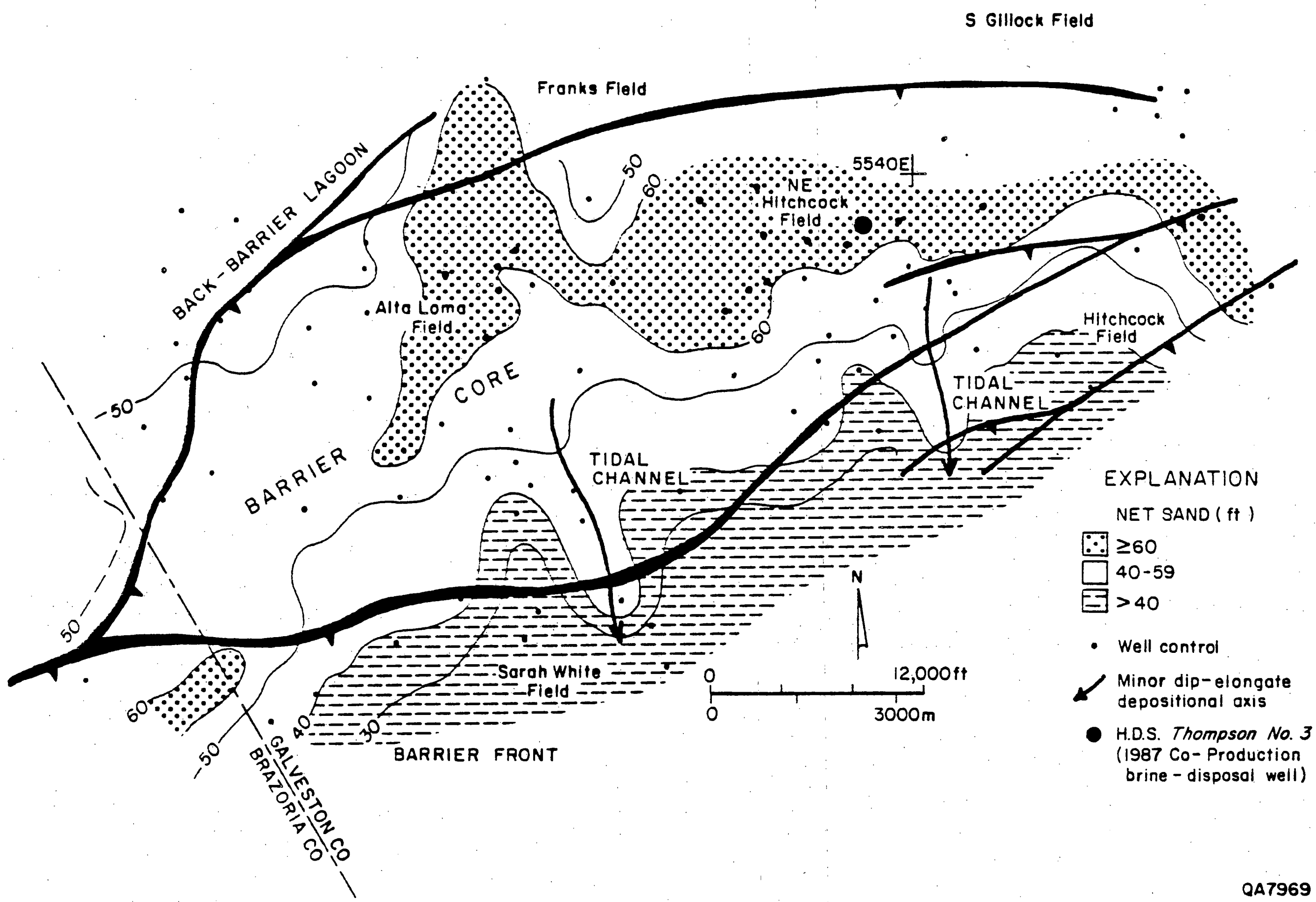

Figure 15. Net-sand and depositional-facies map of the 5,460-ft sand (lower Miocene). This sand is very similar to the 3,780-ft sand (fig. 13) and is ideal for disposal of large volumes of brine. The 5,460-ft sand consists of a well-developed barrier core that is continuous throughout the field.

Table 2. Estimated pore volumes in Miocene sands, Northeast Hitchcock and Alta Loma fields.

A. Primary brine-disposal sands

Sand	Pore volume (bbl)	Limiting factors
3780 ft	2,903,700,000	Virtually none; sheet sand, with minor heterogeneities due to tidal channels and washovers.
4240 ft	3,071,000,000	Minor number of sand-poor areas separated by lobate distributary channel sand bodies.
5460 ft	2,131,000,000	Virtually none; barrier-island sheet sand.

Total pore volume, primary sands:
8,105,700,000 bbl

B. Alternate brine-disposal sands

Sand	Pore volume (bbl)	Limiting factors
2030 ft	1,764,900,000	High number of reservoir heterogeneities, due to fluvial channel sands encased in floodplain muds.
5750 ft	8,030,700,000	Contains numerous shale breaks and permeability barriers. Several genetic subunits in the 5750-ft sand result in a complex internal structure.
6150 ft	1,979,500,000	Virtually none; barrier-island sheet sand.

Total pore volume, alternate sands:
11,775,100,000 bbl

Total pore volume, all sands:
19,880,800,000 bbl

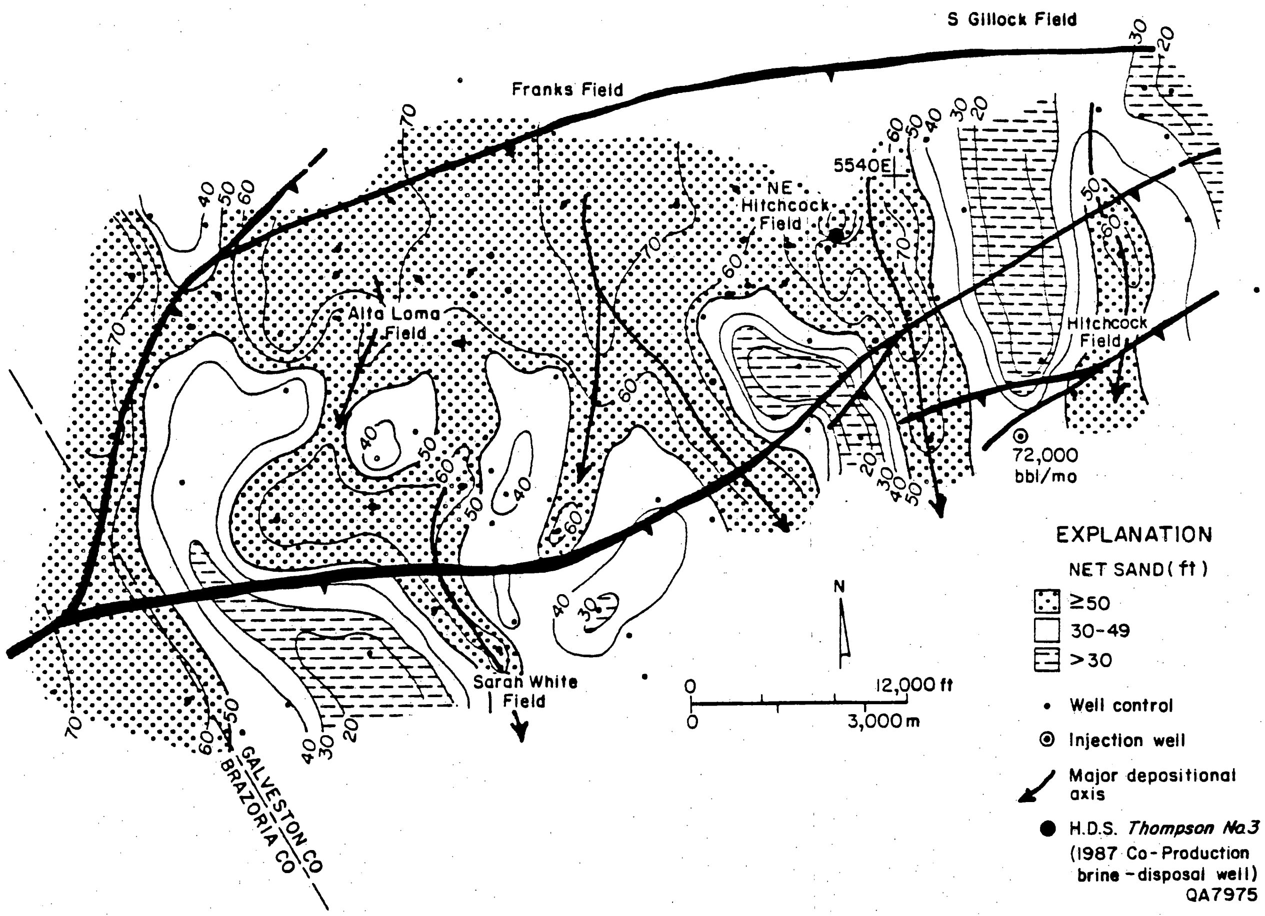

Figure 16. Net-sand map of the 2,030-ft sand (upper Miocene), which is included as an alternate choice for brine disposal because of its shallow depth of burial and the extensive development of 50 to 75 ft of sand in the area. However, several sand-poor areas exist in this depositional unit because of the lenticular nature of distributary sand bodies in the southern part of the fault block.

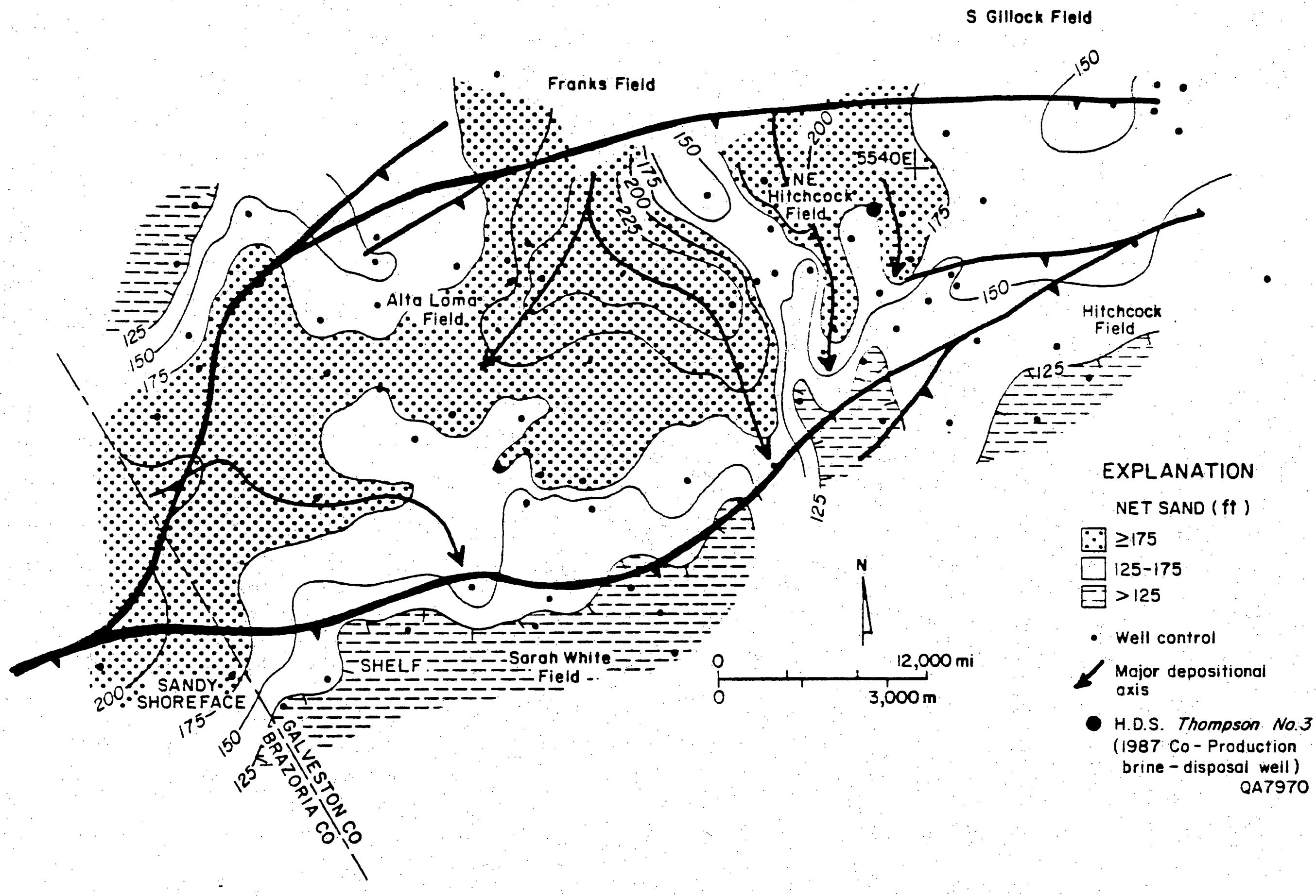

Figure 17. Net-sand and depositional-facies map of the 5,750-ft sand (lower Miocene). This interval contains thick, permeable barrier-island sands suitable for brine disposal. However, the 5,750-ft sand is a composite of several barrier-island depositional units and contains numerous shale interbeds that may limit the net brine-disposal potential.

sands, but it also contains many interbedded mud layers because it contains several individual barrier-island units. Some of these mud layers are 25 ft thick and may restrict the flow of injected fluids to small compartments within the interval. The 6,150-ft sand (fig. 18) is a laterally continuous barrier-island sand as well, but it is more deeply buried, and therefore requires a higher injection pressure for brine disposal than do most other Miocene sands in the field.

RECENT WORK

Coring Program

The Bureau of Economic Geology proposed coring the three primary Miocene barrier-island sands (3,780 ft, 4,240 ft, and 5,460 ft) in a new brine-disposal well to be drilled in one of the sites in Northeast Hitchcock field recommended by Tyler and others (1987). Whole cores, 20 ft long, were to be taken from each of these sands. The main objectives of obtaining cores were to provide representative samples of the middle and lower Miocene section, to refine previous interpretations of environments of deposition presented in Tyler and others (1987), and to provide additional data on the brine-disposal potential of these sands. Other important objectives of taking the cores included petrologic and diagenetic studies related to fluid sensitivity, determination of basic rock properties such as porosity and permeability, investigation of formation water and rock compatibility, and solutions for potential problems in migration of fines. Approximately 60 sidewall cores also were taken throughout the entire Miocene interval (6,350 ft to 2,000 ft) in Northeast Hitchcock field to provide porosity and permeability data from other sands that were not cored.

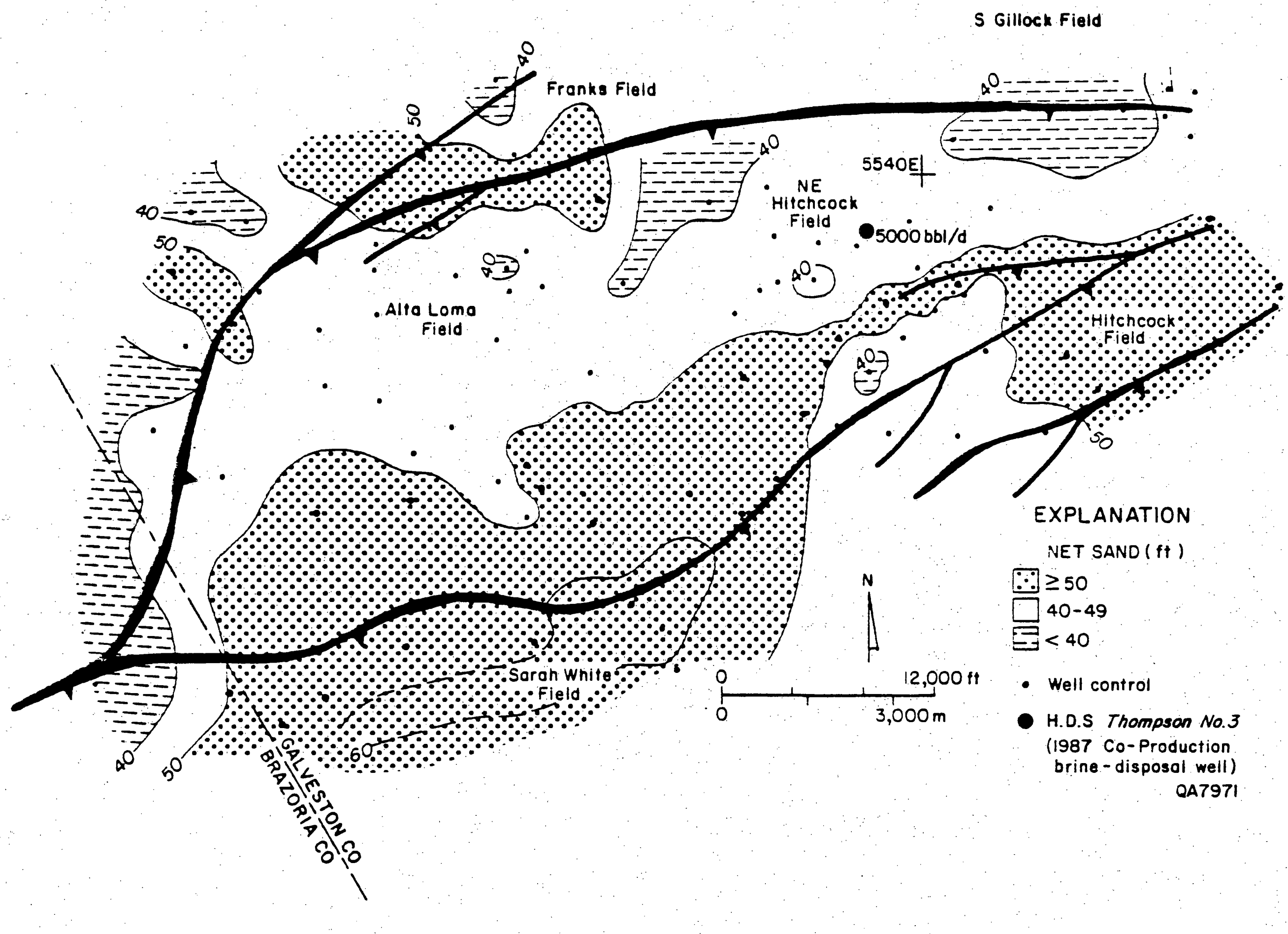

Figure 18. Net-sand map of the 6,150-ft sand (lower Miocene), which has received more than 5,000 barrels of brine per day from October 1987 to August 1988. Good sand continuity in barrier-core deposits in the 6,150-ft sand is developed throughout the Northeast Hitchcock-Alta Loma fault block.

Brine-Disposal Well

In August 1987 a co-production brine-disposal well (H. D. S. Thompson No. 3; well 26A in fig. 10) was drilled to a total depth of 6,350 ft in the lower Miocene in Northeast Hitchcock field. The objectives in drilling this well were to contact the three primary brine-disposal sands (3,780 ft, 4,240 ft, and 5,460 ft) in one of the recommended sites, to obtain whole and sidewall core samples from these sands, to provide a geological and engineering description of the cores, to run a variety of electrical logs for evaluation of the formation, and to select the best sand for initial brine-disposal in the well on the basis of a review of all available data obtained from cores and electric logs from the well. Although the coring apparatus failed to retrieve any part of the 3,780-ft sand, approximately 17 ft of the 4,240-ft sand and 20 ft of the 5,460-ft sand were recovered. The 6,150-ft sand was cored as an alternate to the 3,780-ft sand.

Results of Core Analysis

Three major barrier-island facies (barrier core, tidal inlet, and lower shoreface) are recognized in the cores of lower and middle Miocene sands in the H. D. S. Thompson No. 3 well. Detailed geologic description and analyses of basic rock properties such as mineralogy, texture, permeability, and porosity of sediments in these cores, combined with interpretation of net-sand and log-facies maps, facilitated the characterization of the brine-disposal potential of each of these barrier-island facies, leading to the early selection of the 6,150-ft sand for brine disposal. Initial results have fulfilled expectations for disposal of large volumes of Frio brines; the 6,150-ft sand, which contains homogeneous, high-permeability lower shoreface and barrier-core sands, has already received approximately 5,000 bbl of brine per day since October 1987.

Barrier-Island Depositional Systems

Lower Miocene barrier islands in the Texas Gulf Coast were deposited on a coastline having relatively high wave energy and low tidal range (Galloway and others, 1986). Barrier islands deposited on wave-dominated coastlines have elongate, linear barrier axes that are separated by tidal inlets at widely spaced intervals; facies typically consist of a wedge- or tabular-shaped barrier core and upper shoreface, wedge-shaped lower shoreface, lenticular, crosscutting tidal inlets, lobate flood-tidal deltas and washover fans in the back-barrier environment, and small, lobate ebb-tidal deltas in the fore-barrier environment (fig. 19). Barrier-island sand bodies are typically tabular, consisting of sheetlike wedges developed in bands parallel to the shoreline. They are internally homogeneous and can contain large reservoir or aquifer volumes, compared with other clastic depositional systems.

Barrier-core facies represent the massive, strike-elongate framework of the barrier island and are a composite of well-sorted beach, upper shoreface, and dune sands (fig. 19). The barrier core is one of the most homogeneous components of barrier-island systems because internal stratification and variations in grain size are poorly developed. Together with associated shoreface facies, the barrier core contains large volumes of clean, well-sorted sand with few discontinuous mud layers; it therefore has an excellent brine-disposal potential.

The lower shoreface represents the seaward margin of the barrier core and extends seaward from the outermost bar to the break in slope between the shoreface toe and the flat shelf (McCubbin, 1982). Lower shoreface deposits are muddier and more heterogeneous than barrier-core deposits because they accumulate in a lower-energy setting offshore. They are typically upward-coarsening, grading upward from interbedded inner-shelf silt and mud to crossbedded and planar bedded fore-barrier sands. The geometry of the lower shoreface facies is strike parallel, similar to that of the barrier-core facies (fig. 19).

Tidal inlets are deep, narrow channels that cut across barrier islands, acting as conduits through which sediments are transported back and forth from inner-shelf to back-barrier

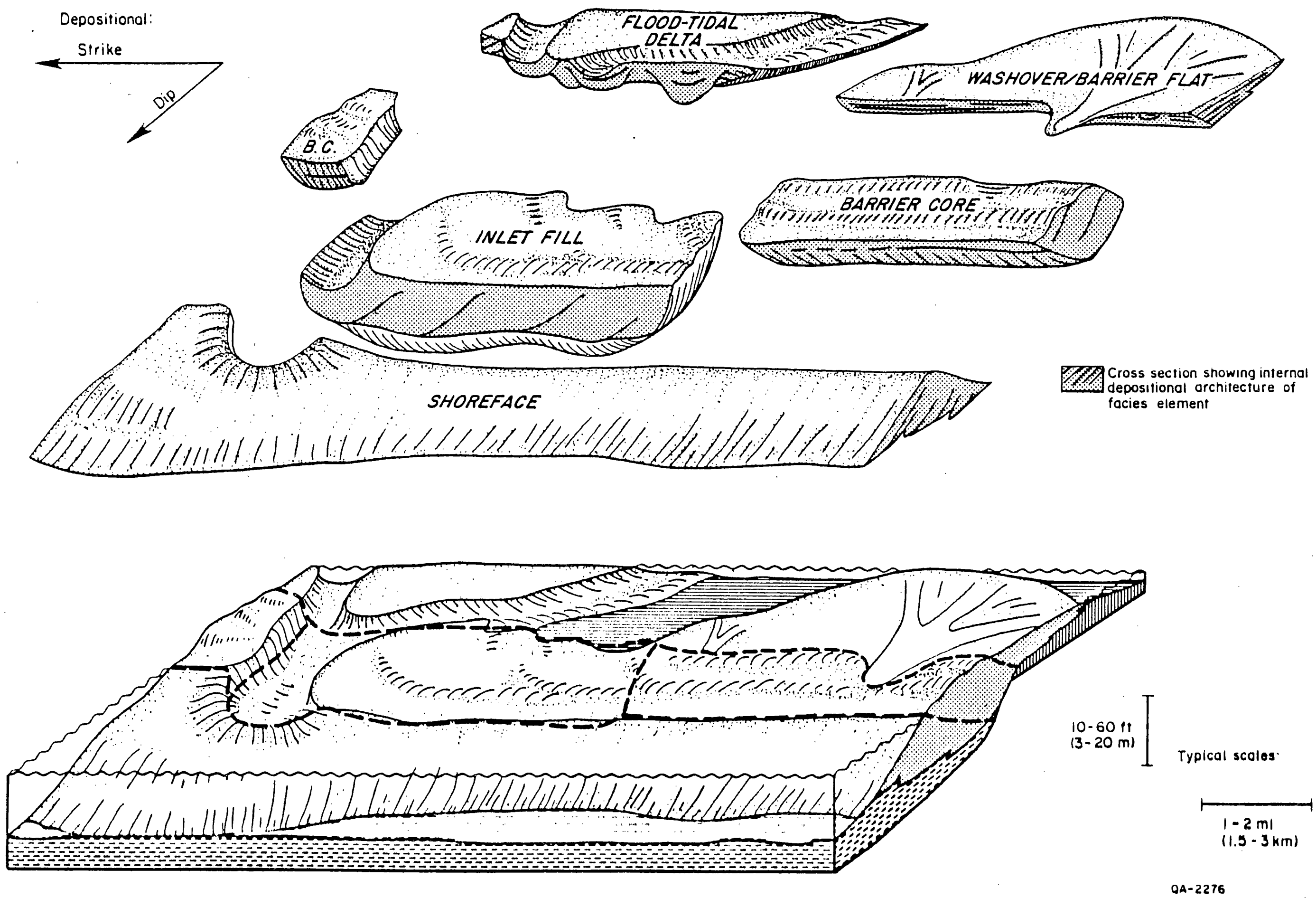

Figure 19. Facies architecture of microtidal barrier islands. Lateral continuity of homogeneous barrier-core and barrier-shoreface facies is commonly disrupted by dip-parallel, heterogeneous tidal-inlet facies. Flood-tidal delta and washover fan facies form other intrareservoir compartments that pinch out landward into muddy lagoonal sediments (from Galloway and Cheng, 1985).

environments. Wave-dominated tidal inlets migrate laterally along the shoreline for many miles in the direction of longshore drift, eroding into previously deposited facies (Moslow and Tye, 1985). Inlet-fill facies typically consist of erosionally bounded deposits that accumulate on the updrift margin of the inlet (fig. 19). They tend to be internally heterogeneous, having a basal lag consisting of shell debris and an upward-fining texture that represents channel infilling and abandonment. Inlet-fill sequences are commonly capped by upward-coarsening sediments deposited by lateral accretion of spit platforms and barriers that accrete laterally over the abandoned inlet fill (Heron and others, 1984).

Core Descriptions

Barrier-core facies in the 5,460-ft sand (fig. 20) and upper 10.5 ft of the 6,150-ft sand (fig. 21) have the greatest potential for brine disposal of all other facies in cores of the H. D. S. Thompson No. 3 well. Barrier-core facies in these cores are composed of clean, upward-coarsening sand; grain sorting and roundness increases upward, shell fragments and mud layers are uncommon, and no calcite-cemented zones are observed. Analysis of the H. D. S. Thompson No. 3 cores indicates that the barrier-core facies contains less clay than do either the tidal-inlet or lower shoreface facies, and that sands in this facies have the best sorting and texture index and the highest permeability to Frio Formation water (table 3).

In contrast to the barrier-core facies in the 5,460-ft sand, the tidal-inlet facies in the 4,240-ft sand and in the lower 6 ft of the 6,150-ft sand (fig. 22) is a less favorable choice for brine disposal because it is moderately to poorly sorted, containing mud interbeds and thin, tightly calcite-cemented zones that serve as permeability barriers. In the 4,240-ft sand, the tidal-inlet facies is about 9 ft thick (fig. 22). The lower 5 ft contains several irregular, erosional surfaces characterized by a medium- and coarse-grained lag of abraded shells. Thin (2- to 4-inch) zones of calcite cement, caused by dissolution of shell material, are most common in the lower inlet-fill section. These cemented zones result in a reduction of the net brine-disposal potential of the sand by reducing the

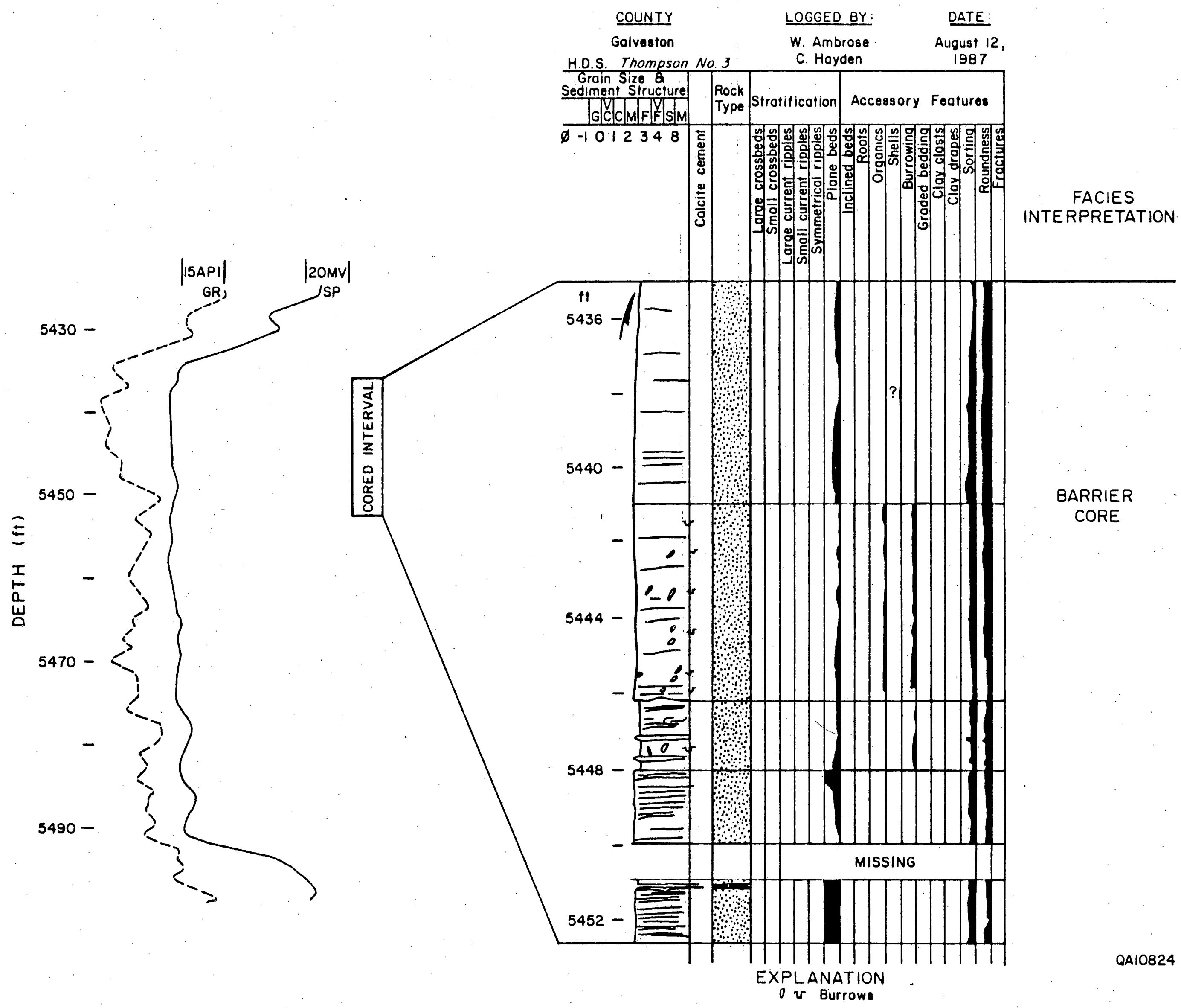

Figure 20. Core description and log response of the 5,460-ft sand (lower Miocene) from the H. D. S. Thompson No. 3 brine-disposal well in Northeast Hitchcock field.

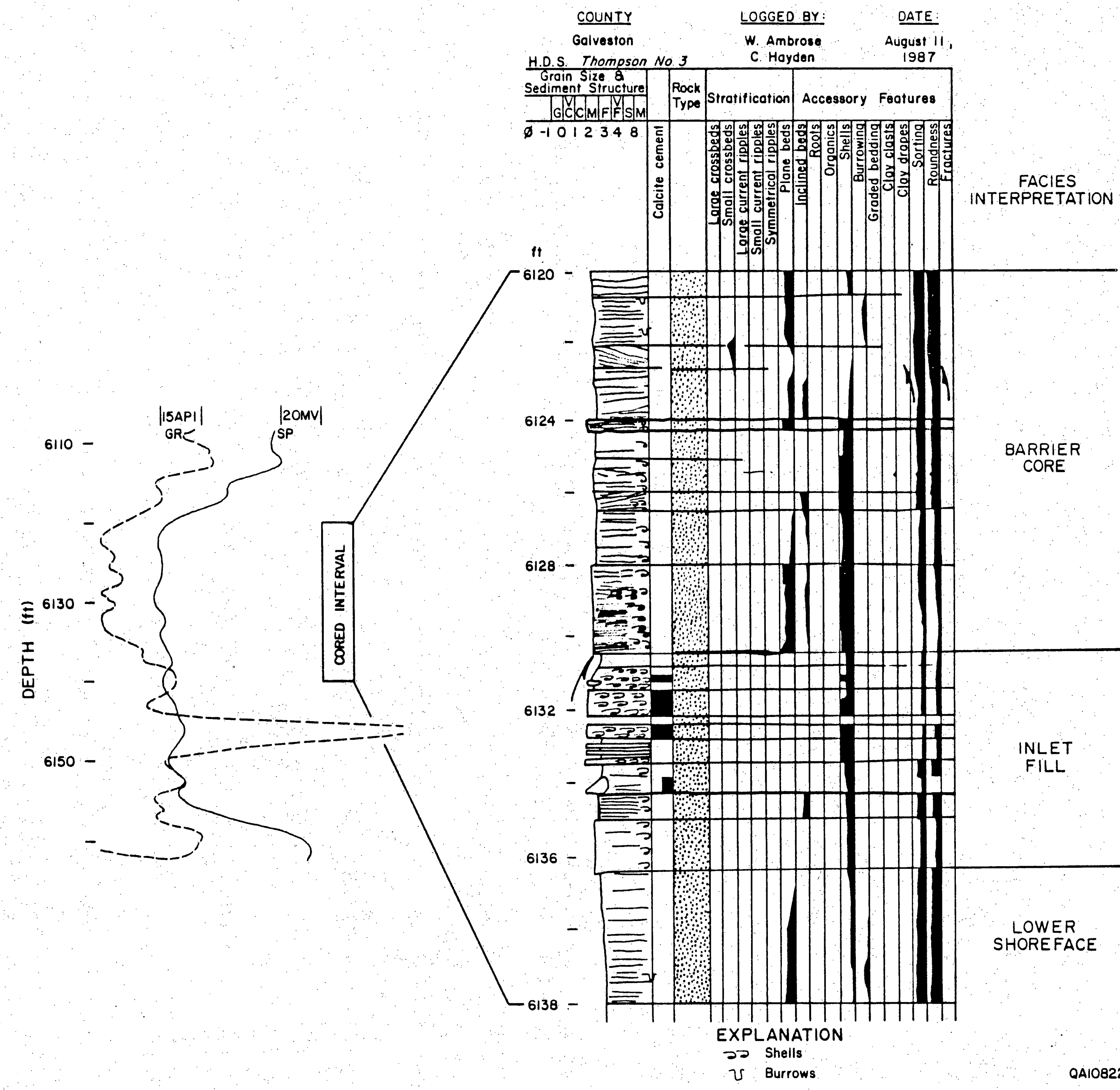

Figure 21. Core description and log response of the 6,150-ft sand (lower Miocene) from the H. D. S. Thompson No. 3 brine-disposal well in Northeast Hitchcock field.

Table 3. Reservoir properties of Miocene barrier-island sands cored in the H. D. S. Thompson No. 3 brine-disposal well.

	Facies		
	Barrier Core	Tidal Inlet	Lower Shoreface
Sand Body and Interval (ft)	5,460 (5435-5452.5) 6,150 (6120-6130)	4,240 (4240-4253) 6,150 (6130-6136)	4,240 (4253-4259.5) 6,150 (6136-6140)
Mineralogy (percent)			
Quartz	75	74	59
Feldspar	19	10	25
Calcite	0	3	3
Clay	5	12	12
Other	1: Fe-Dolomite	1: Pyrite	1: Pyrite or Fe-Dolomite
Median Grain Size (phi)	2.73	2.92	3.19
Standard Deviation in Grain Size (phi)	0.97	1.05	1.04
Permeability to Frio Water (md)	2,570	None Reported	1,890
Porosity (percent)	32	None Reported	35
Texture Index	29	48	None Reported

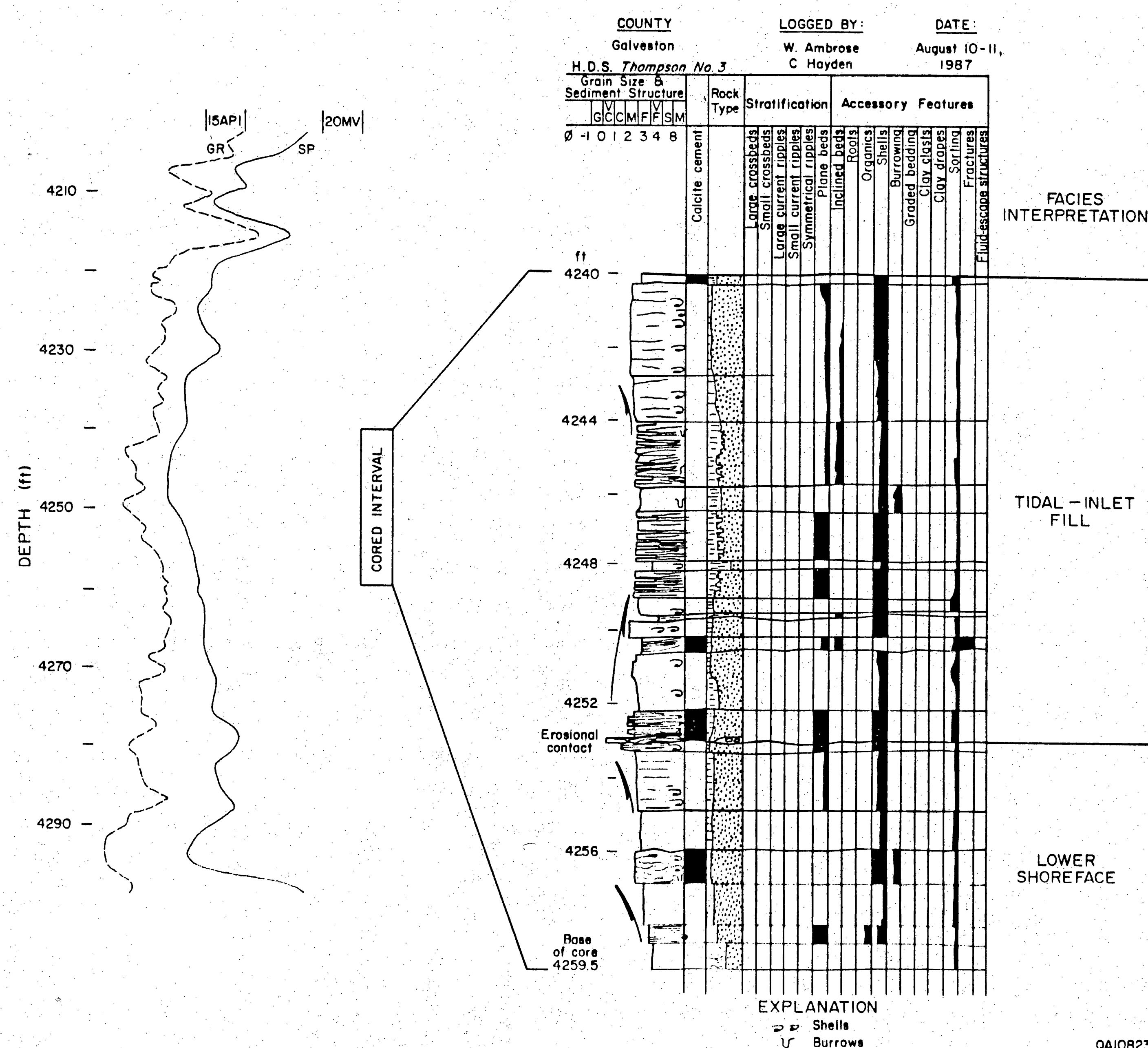

Figure 22. Core description and log response of the 4,240-ft sand (middle Miocene) from the H. D. S. Thompson No. 3 brine-disposal well in Northeast Hitchcock field.

net kh (permeability multiplied by thickness) of the sand and by acting as barriers to fluid flow. Grain sorting in the tidal-inlet facies is worse than it is in either the barrier-core or lower shoreface facies, although median grain size is greater than in the lower shoreface (table 3).

Lower shoreface facies are observed in the lower 6.5 ft of the 4,240-ft sand and from a 4-ft-thick interval in the 6,150-ft sand from 6,136 ft to 6,140 ft. This facies consists of sparsely burrowed, very fine grained sand and thin bands of interbedded silt. Although the lower shoreface has lower permeability to Frio Formation water than does the barrier-core facies (1,890 md versus 2,570 md), permeability in this facies is still acceptable for brine disposal.

Brine Disposal in the 6,150-Ft Sand

In mid-October 1987 Frio brines were injected into the 6,150-ft sand in the H. D. S. Thompson No. 3 well (26A, fig. 10). This sand was selected for initial brine disposal on the basis of its blanket geometry and excellent average brine permeability of 2,500 md. Other sands that were considered for later up-hole brine disposal in the H. D. S. Thompson No. 3 well were the 5,750-ft, 5,460-ft and 3,780-ft sands, all of which are thick, laterally continuous, and extremely permeable barrier-island sands.

The 6,150-ft sand has received 1,251,343 barrels of brine from mid-October 1987 to August 1, 1988, in a 30-ft-thick interval that has a kh of 40 darcy-ft. Although the 6,150-ft sand has received 7,500 barrels of brine per day over periods of several consecutive weeks, this sand has instead throughout its entire brine-disposal history received an average of only 5,000 barrels of brine per day. This has happened because of the high cost of electricity ($64/d) associated with the amount of energy involved in pumping the brines into the formation to depths of 6,150 ft, where the required injection pressure is 364 psia. In order to offset these expenses, the Gas Research Institute received approval from the Railroad Commission of Texas also to dispose of co-production brines into shallow upper Miocene fluvio-deltaic sands at 2,224 ft in a new disposal well (S.G.R. Prets No. 2; fig. 10) and to re-enter an older well (Phillips Thompson No. 2, also known as Phillips

Delaney No. 1; well No. 21, fig. 10) in Northeast Hitchcock field, where brines were injected into lower Pliocene sands at 1,720 ft. Power costs for these sands are lower because of the shallow depths involved. For example, the electricity costs for disposal in the 2,224-ft sand are only $32/d. However, these sands had a lower initial injectivity index (108 for the 2,224-ft sand and 53 for the 1,720-ft sand) than did the 6,150-ft sand, which had an injectivity index of 125. The injectivity index is defined as the number of barrels injected per day, divided by the injection pressure, in psia. Additionally, the 6,150-ft sand has a much higher kh product (40 darcy-ft) than does the 1,720-ft sand (10 darcy-ft) over a comparably thick injection interval.

FURTHER RECOMMENDATIONS

Several important factors such as depth, sand-body geometry, and total pore volume available for injection must be considered in selecting effective but economic brine-disposal sands. The best sand for future up-hole disposal in the H. D. S. Thompson No. 3 well is the middle Miocene 3,780-ft sand, a laterally continuous barrier-island sand that has an average thickness of 70 ft, in contrast with the shallow but heterogeneous upper Miocene 2,224-ft sand, which has an average thickness of only 25 ft in Northeast Hitchcock field. Power costs for brine-disposal pumps in the 3,780-ft sand should be only about $45/d instead of $64/d in the 6,150-ft sand, which is currently receiving brines in the H. D. S. Thompson No. 3 well. Additionally, the 3,780-ft sand has 3 billion barrels or more of pore volume available for brine disposal in the Northeast Hitchcock-Alta Loma fault block, and approximately 3 times as much in the 2,224-ft sand, which has a heterogeneous sand-body geometry similar to that of the 2,030-ft sand (fig. 16). Finally, the 3,780-ft sand is deeper below the base of the fresh water aquifer than either the 2,224-ft or 1,720-ft sands in Northeast Hitchcock field and therefore presents less risk of fresh-water contamination.

CONCLUSIONS

Core analysis and brine-disposal histories of lower and middle Miocene sands confirm previous conclusions by Tyler and others (1987) that barrier-island sands are capable of receiving large volumes of brines co-produced from the Frio 1-A reservoir in Northeast Hitchcock field. These sands are ideal, from a geological perspective, for brine disposal because they have high permeabilities in excess of 2,000 md, are internally homogeneous, and have a great lateral extent in the field, resulting in large amounts of pore volumes available for brine disposal without much pressure buildup.

Certain barrier-island sands in Northeast Hitchcock field, such as the 4,240-ft sand, contain large volumes of heterogeneous, poorly sorted tidal-inlet facies. This facies also contains minor amounts of tightly calcite-cemented zones as a consequence of postdepositional dissolution of shells at the base of the tidal inlet. The net brine-disposal potential of the 4,240-ft sand should be lower than other barrier-island sands, such as the 5,460 ft and 6,150 ft, which are dominantly composed of homogenous, well-sorted barrier-core facies. This facies has been found to have less clay and calcite cement than does the tidal-inlet facies on the basis of the study of cores obtained from the H. D. S. Thompson No. 3 brine-disposal well.

The middle Miocene 3,780-ft sand is recommended over the 4,240-ft sand for future up-hole brine disposal in the H. D. S. Thompson No. 3 well because it best satisfies geological and economic criteria for brine disposal in other Miocene sands above the 6,150-ft sand, which is currently receiving brines. Some of the most laterally continuous upper Miocene fluvial and deltaic sands are reasonable choices for future up-hole brine disposal in the H. D. S. Thompson No. 3 well because, since they are not as deeply buried, these sands can accept brines at lower costs. However, these sands have a lower net brine-disposal capacity than middle and lower Miocene barrier-island sands because they are discontinuous and have a complex sand-body architecture. Future selection of brine-disposal sands in Northeast Hitchcock field and in other areas must be made after consideration of several important factors that include brine-disposal history of the area as well as sand-body complexity, thickness, and depth of burial.

SECONDARY GAS RECOVERY: CASE STUDIES IN SEELIGSON FIELD, JIM WELLS COUNTY, TEXAS

by

Lee A. Jirik

INTRODUCTION

Exploring for unrecovered gas in a mature hydrocarbon province can lead to a better cost-effective source of reserve additions compared with new field exploration because exploration costs currently account for about 60 percent of the cost of finding and developing a new gas field. Furthermore, reserve additions from known fields benefit from investments already made in reservoir development and production infrastructure. Extension of new recovery techniques to exploring for gas in known fields involves reserve additions from untapped compartments within established reservoirs and recompletion of bypassed reservoirs through evaluation of cased-hole logging techniques. This study presents case histories documenting geological methods applied to the maximization of recovery of gas from conventional reservoirs in a mature field.

Seeligson field lies in the highly prolific Frio fluvial/deltaic hydrocarbon play along the margin of the Vicksburg Fault Zone in South Texas (Kosters and others, in press). Characteristic of the fields in this play, Seeligson field is composed of multiple, vertically stacked reservoirs containing hydrocarbons trapped primarily in rollover anticlines downdip of the major Vicksburg growth fault. The highly complex depositional architecture of these reservoirs makes it probable that gas is contained in numerous undrained compartments. Additionally, bypassed gas (gas-bearing zones that have not been identified as gas productive) may be encountered within or uphole from a producing interval. Detailed geological analyses of selected reservoirs within Seeligson field demonstrate how advanced characterization of reservoir geometries and depositional environments can be effectively used to identify unrecovered gas zones and to select potential recompletion prospects.

Objectives

The overall objective of the study was to establish a cooperative research and development program with industry in order to develop, test, and verify methods and technologies with near- to midterm potential for maximizing recovery of cost-competitive gas from conventional reservoirs. Specific objectives were: (1) to identify a suitable field available for study. Field selection was the result of a screening process involving numerous geologic and engineering factors; (2) to develop a cooperative relationship with the operator of the selected field. This relationship was crucial in the areas of data acquisition, information transfer, and recompletion-strategy development; (3) to establish a data base from which intensive geological analyses might be built, define stratigraphic and structural framework of the field, and select specific reservoirs to be targeted for detailed analysis; (4) using results of the cased-hole evaluation program performed by ResTech, Inc., to identify potential untapped compartments and bypassed gas zones; (5) to apply advanced characterization methods to reservoirs with favorable log analysis results in order to delineate geologically based recompletion strategies; (6) to present recompletion recommendations to the operator.

Study Area and Data Base

Railroad Commission of Texas (RRC) District 4, in South Texas, is the leading nonassociated gas-producing district in Texas, with production mainly from Tertiary Wilcox, Vicksburg, and Frio Formations. South Texas fields often contain multiple stacked, heterogeneous fluvial to fluvial-deltaic reservoirs that trap hydrocarbons along regional growth-fault trends. More than 200 gas fields located in District 4 were evaluated as potential study areas for the Secondary Gas Recovery Project. Data from RRC and other commercial sources were compiled to determine field location and size, reservoir age, and cumulative production. Seeligson field was selected as the study area because of its geologic setting, stratigraphic and structural framework, production history, and availability of data. The willingness of unit operator Sun Exploration and Production Company to participate in the cooperative program also played an important part.

Seeligson field is located in Jim Wells and Kleberg Counties, along the margin of the extensive Vicksburg Fault Zone (fig. 23). The field is bounded updip by a large northeast-southwest trending growth fault that offsets Frio sands several hundred feet. The eastern, downdip boundary of the field is defined primarily by the limits of production because no significant bounding faults segment the field into a well-defined block. Within the field, subsidiary highs occur on the primary rollover anticline that defines the structural configuration of the field (fig. 24). Seeligson field covers approximately 50 mi^2, and this study focuses on unitized Frio reservoirs within a 9-mi^2 area in the central part of the field (fig. 24).

The data base consists of more than 330 well logs distributed throughout the field; approximately 250 are located within the study area. A base map was prepared using current, unitized well numbers (fig. 25); well names and numbering systems used prior to unitization are not included in this report. Additional data used in the study were modern log suites for several wells within the area, for example, sonic, neutron/density, and thermal-decay-time (TDT) logs and repeat-formation testers (RFT); mineralogic analyses; whole-core and core analysis reports. Well history summaries for more than 100 wells in the study area provided crucial completion and production information. Bottom-hole pressure data (BHP's) were acquired for wells producing from Zone 15. Sun Exploration and Production Company provided most of the well log, well history, and pressure data used in this study. The Bureau of Economic Geology and ResTech, Inc., proposed and completed a data collection program in the Sun P. Canales No. 141 well, drilled in November 1987, which included the acquisition of 36 ft of whole core, an open-hole sonic log (BHC), RFT data in several sandstones, sidewall cores in sandstones and shales throughout the unit, and a full-waveform cased-hole sonic log.

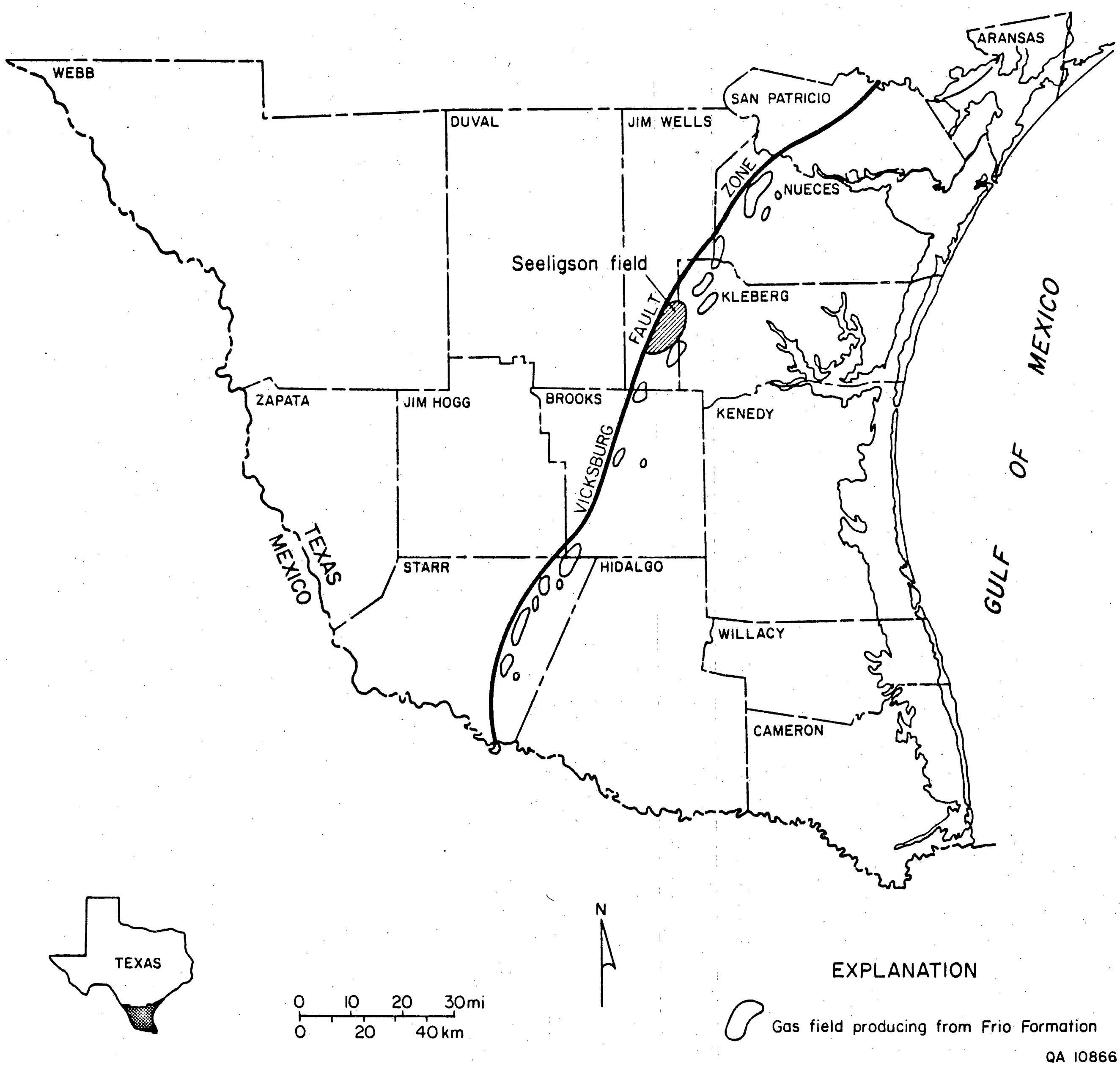

Figure 23. Location of Seeligson field, Jim Wells and Kleberg Counties, Texas. Seeligson field is located along the margin of the Vicksburg Fault Zone in a highly prolific Frio hydrocarbon play.

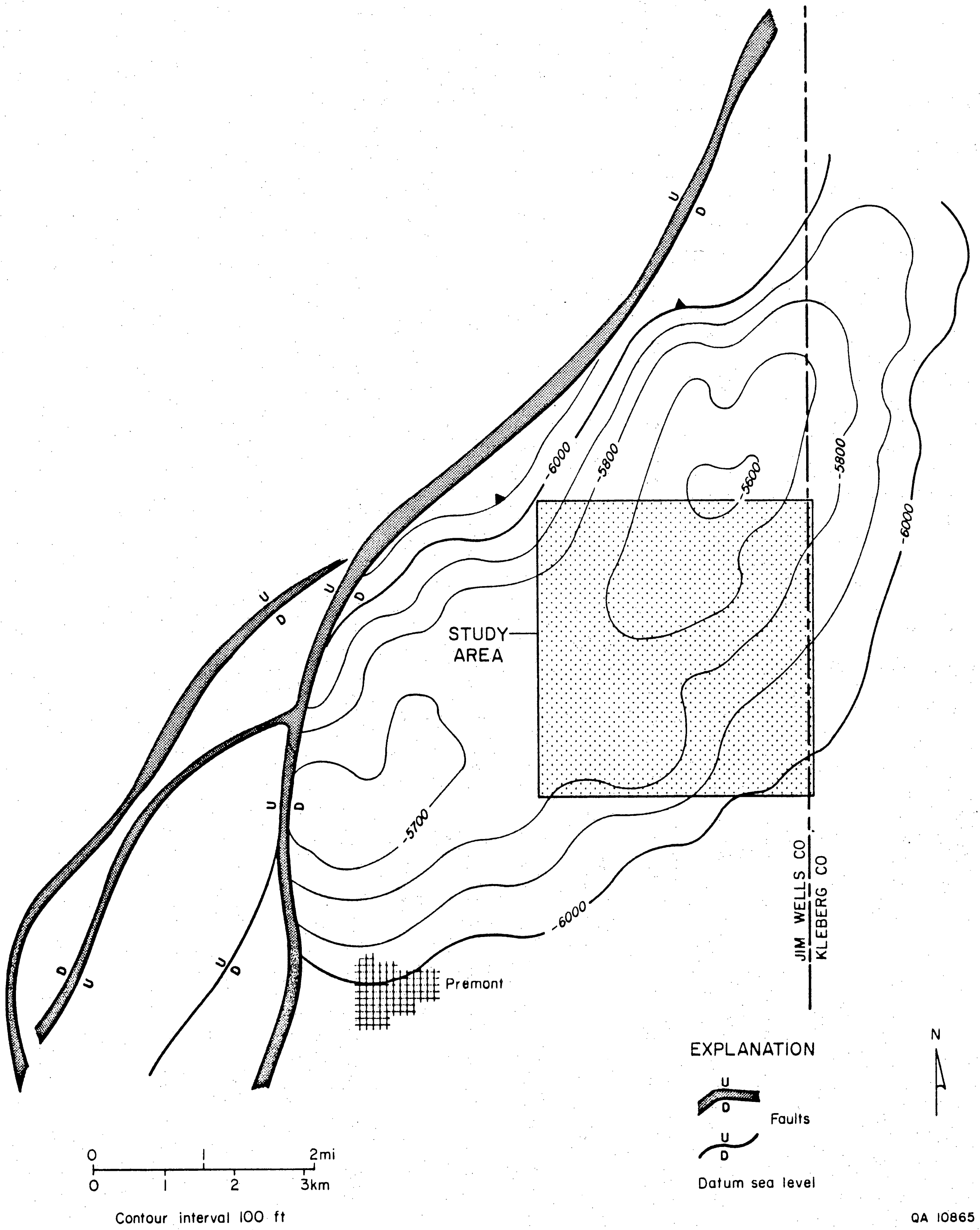

Figure 24. Structure map of Seeligson field, contoured on the Textularia mississippiensis (lower Frio) zone. The principal growth fault, with throws from 300 to 1,700 ft, forms the western boundary of the field. This study focused primarily on a 9-mi^2 area in the east-central part of the field (modified from Geomap, Inc., 1988).

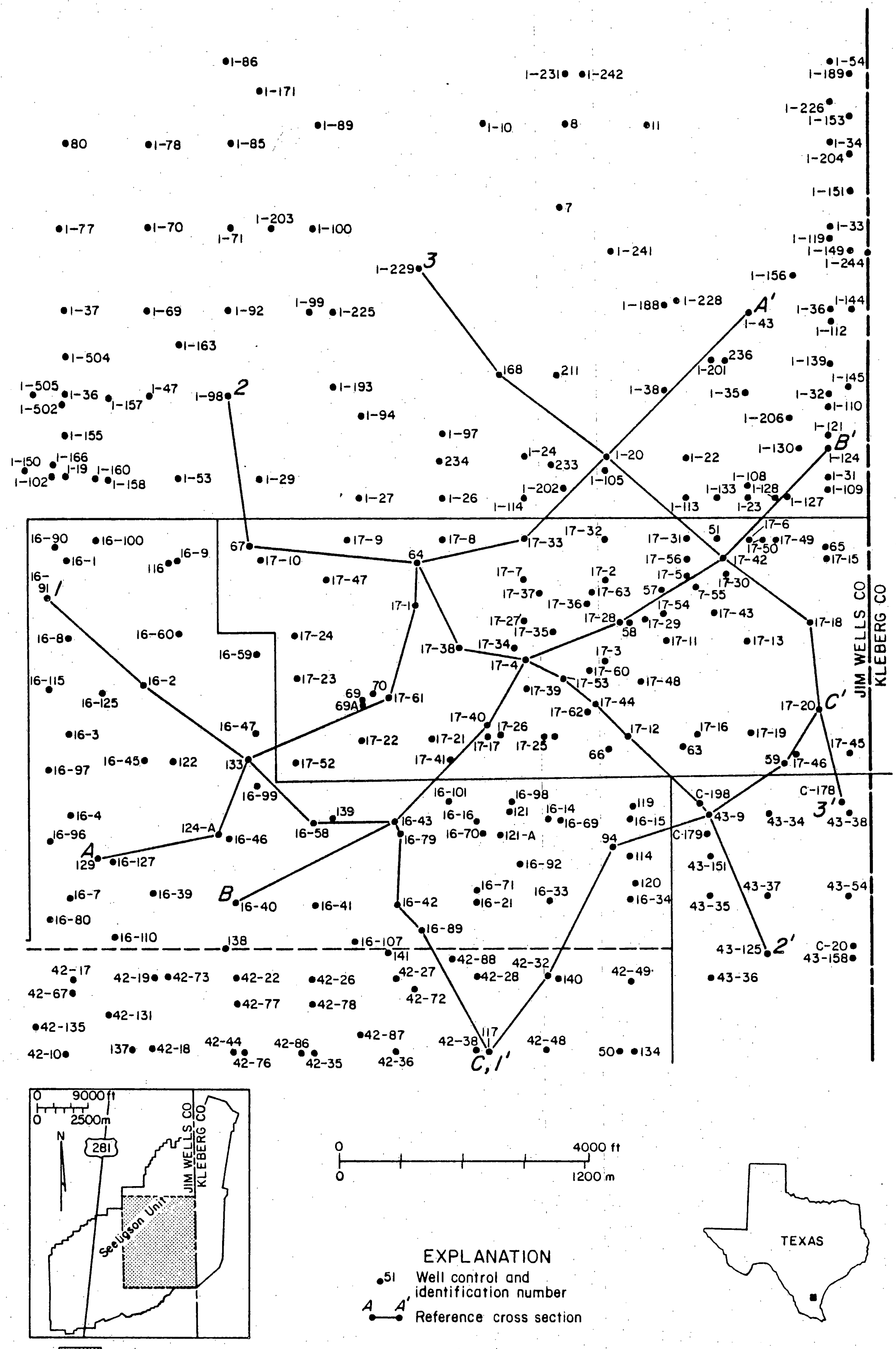

Figure 25. Base map of study area within Seeligson field showing well control, identifying well numbers, and grid of reference cross sections.

Methods

A grid of six structural cross sections (three strike oriented and three dip oriented) was constructed across the study area to illustrate the lateral extent, thickness, and variability of sandstone reservoirs within the unit (fig. 25). More than 30 reservoirs are productive from the unit in the study area. Aggregate zones display varying degrees of heterogeneity; more than 20 zones are illustrated on schematic strike cross section A-A' (fig. 26). Net-sandstone-isopach and depositional-facies maps based on SP log patterns were constructed for 30 sandstones in the unit. Net-sandstone thickness was determined from electric logs using a cutoff line drawn approximately one-third of the distance from the SP baseline to the maximum SP deflection for sandstones within the unit. Depositional-facies maps were based on characteristic SP patterns that were interpreted in conjunction with net-sandstone maps. This method of mapping has been effectively used in previous studies of the Frio along the Texas Gulf Coast (Galloway and Cheng, 1985; Tyler and Ambrose, 1985; Ambrose and Jackson, 1988).

Two sandstone zones were chosen for intensive study. Initial consideration was given to reservoirs showing the greatest lateral variability, although final selection involved numerous factors, including log analysis results, production histories, and BHP characteristics. Several detailed stratigraphic cross sections and net-sandstone-isopach and SP log-facies maps were prepared in order to illustrate lateral relationships, sandstone distribution, and facies variations of the specific zones of interest.

Well-completion and production data were compiled from summaries provided by Sun Exploration and Production Company and from information available at the Railroad Commission of Texas and integrated into the study.

Whole core from the Sun P. Canales No. 141 well was described visually. Petrographic analyses were performed on seven thin sections taken from core plug trim tips, and 34 thin sections were prepared and analyzed from sidewall core taken in the well. Several samples of whole core

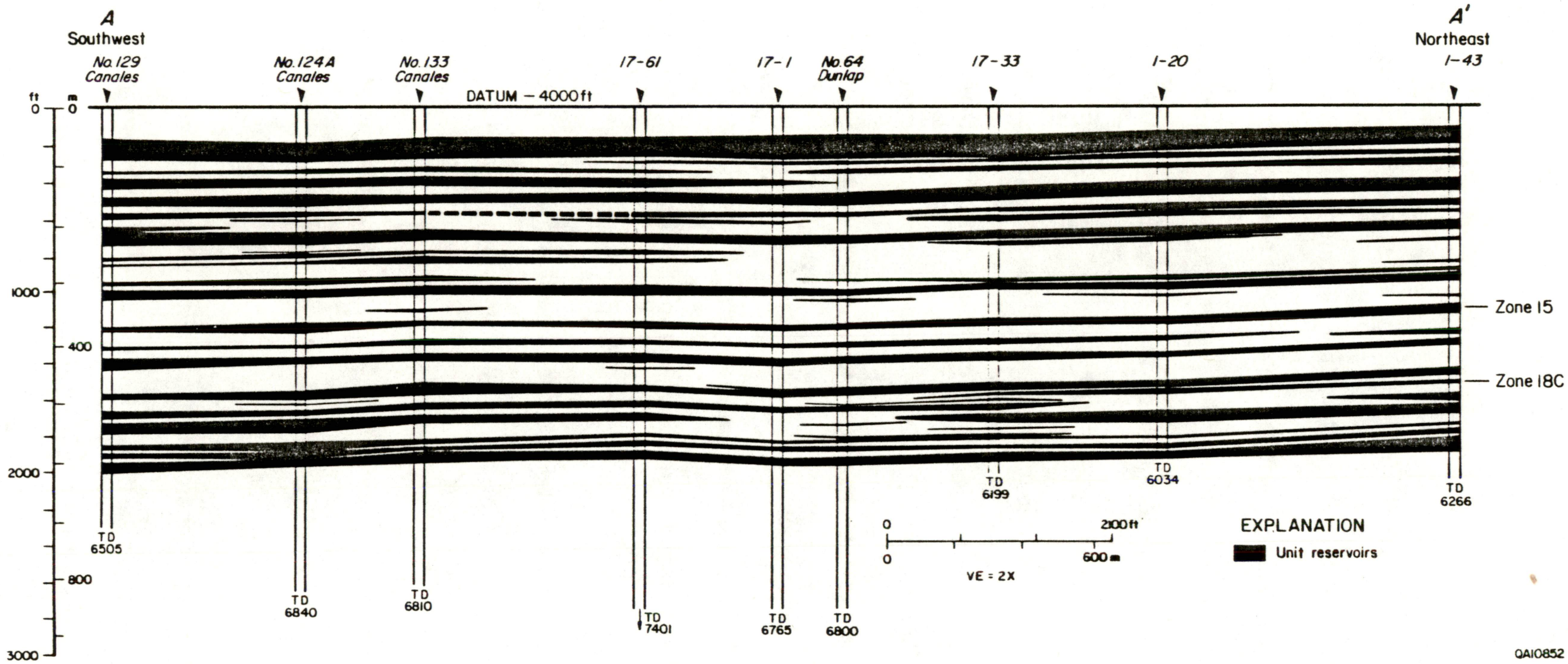

Figure 26. Schematic structural strike-section A-A' through east-central part of Seeligson field (see fig. 25 for location). Multiple, vertically stacked, multilateral reservoirs are characteristic of the field. Zones 15 and 18-C were studied in detail.

also were analyzed on the scanning electron microscope (SEM). ResTech, Inc., incorporated the mineralogic data into its petrophysical evaluation of Seeligson wells (Howard and Bolin, 1988).

FRIO DEPOSITIONAL SYSTEMS IN THE TEXAS GULF COAST

The Oligocene Frio Formation is one of the principal progradational wedges of the Gulf Coast Basin, an extracratonic basin characterized by rapid subsidence in areas of sediment loading; Frio sediments were deposited along its northern margin. Thickness of Frio sediments accumulated to 10,000 ft or more where the continental shelf built basinward beyond the underlying Mesozoic shelf margin. Galloway and others (1982) divided the Frio into separate but related depositional systems primarily on the basis of sandstone-isolith and facies maps. Major progradational depocenters were designated the Houston and Norias delta systems, located in the Houston and Rio Grande Embayments, respectively. These delta systems were fed by the Chita-Corrigan fluvial system (Houston delta) and the Gueydan fluvial system (Norias delta). Separating the two major fluvial-deltaic complexes are the Choke Canyon/Flatonia coastal lake-streamplain system and the Greta/Carancahua barrier-strandplain system (Galloway and others, 1982).

South Texas Frio Depositional Systems

Frio sediments in South Texas were deposited by a system of major extrabasinal rivers (the Gueydan fluvial system) along the axis of the Rio Grande Embayment (Galloway, 1977). Seeligson field is located at the downdip edge of this system, near to where it grades into the Norias delta system (fig. 27). The Gueydan fluvial system is characterized by coarse-grained, bed-load channel fill and point-bar sandstones flanked by widespread crevasse splay deposits and floodplain mudstones and siltstones. The Gueydan fluvial system channel-fill sandstones are interpreted to have been deposited in bed-load, straight to slightly sinuous streams having broad, well-developed natural levees (Galloway, 1977, fig. 28). Individual bed thickness of channel-fill sequences is 10

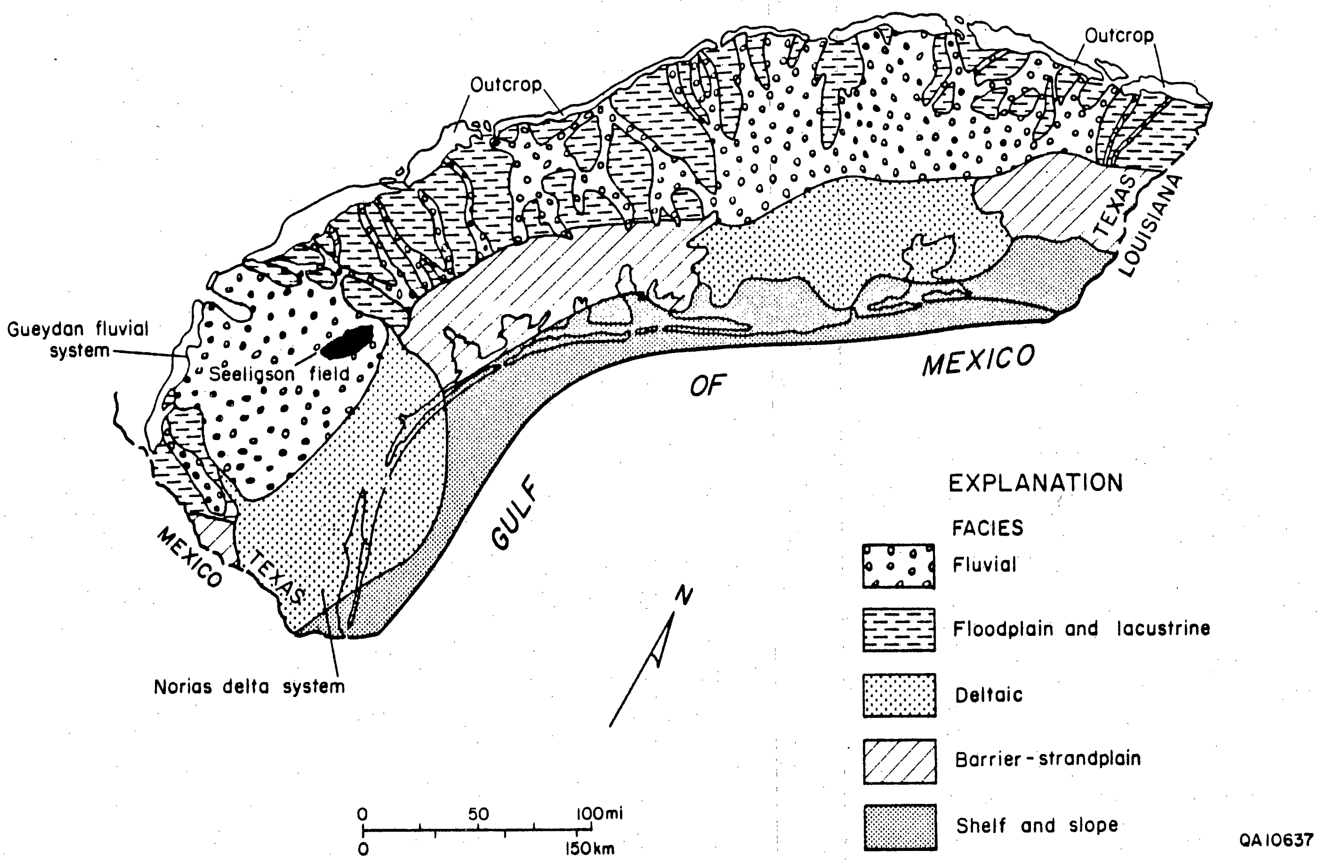

Figure 27. Frio depositional systems along the Texas Gulf Coast. Middle and upper Frio sediments were deposited in the Gueydan fluvial system, which consisted of a network of low-sinuosity bed-load streams in the Rio Grande Embayment (modified from Galloway and others, 1982).

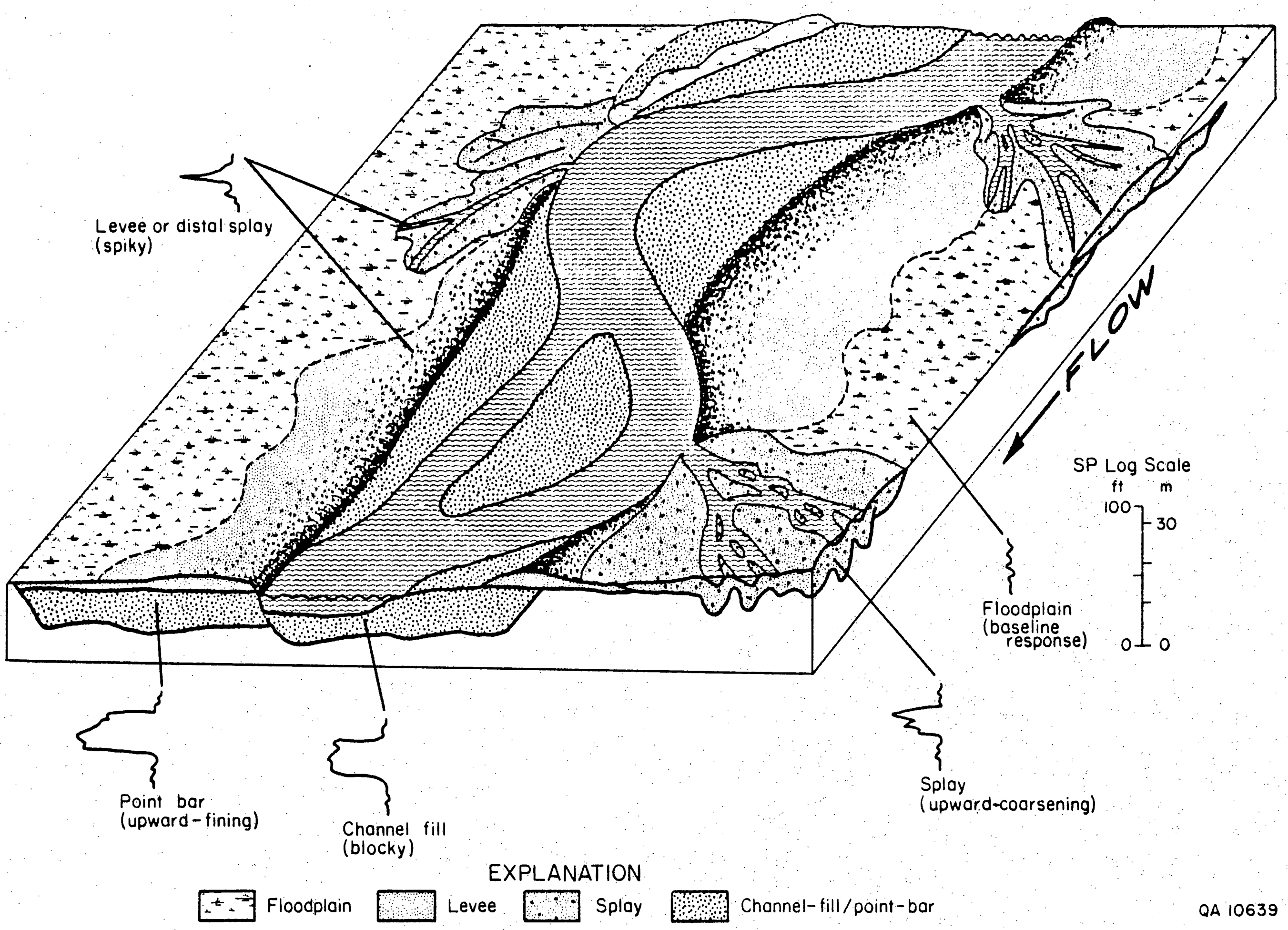

Figure 28. Three-dimensional facies relationships in middle and upper Frio fluvial reservoirs in Seeligson field. Characteristic SP log responses of each facies are shown (modified from Galloway, 1977).

to 30 ft, but sequences are commonly amalgamated into units of as much as 100 ft. These amalgamated sandstone bodies may develop into multilateral belts as much as several miles wide (Galloway, 1982).

Frio Depositional Systems, Seeligson Field

Sandstones of the Seeligson unit display characteristics typical of Gueydan fluvial system deposits. Nanz (1954) described the dip-oriented, lenticular Zone 19-B reservoir as the delta-plain deposit of an Oligocene river, probably an ancestral Rio Grande. Analysis of net-sandstone-isopach maps for 30 productive sandstones within the Seeligson unit reveals predominantly dip-elongate trends common in fluvial provinces. Log-facies maps, used in conjunction with net-sandstone maps, illustrate the spectrum of facies associated with fluvial depositional environments. Maps of Zones 11-B, 17, and 20-B are representative of the trends observed in many of the reservoirs throughout the unit section. Net-sandstone thicknesses range from 2 to 43 ft forming belts of sandstones as much as 1 mi wide oriented normal to regional strike (figs. 29, 30, 31). Channel-fill and point-bar sands, crevasse splay deposits, and levee and overbank siltstones and mudstones, as illustrated on SP log-facies maps, are characteristic facies of Seeligson unit reservoirs (figs. 32, 33, 34). These reservoirs are complex and may contain gas within numerous isolated, undrained compartments.

RESERVOIRS SELECTED AS CANDIDATES FOR RECOMPLETION

The stacked fluvial sandstone bodies and stringers in the Seeligson unit provided numerous opportunities for selecting specific reservoirs for detailed study. Two reservoirs, Zone 15 and Zone 18-C, were ultimately selected as candidates to be evaluated for recompletion. Factors that were considered in the selection of reservoirs for intensive geological analysis include: (1) degree of complexity within the aggregate reservoir to allow identification of component genetic sand bodies (sandstone heterogeneity); (2) results of log analysis performed by ResTech, Inc., including

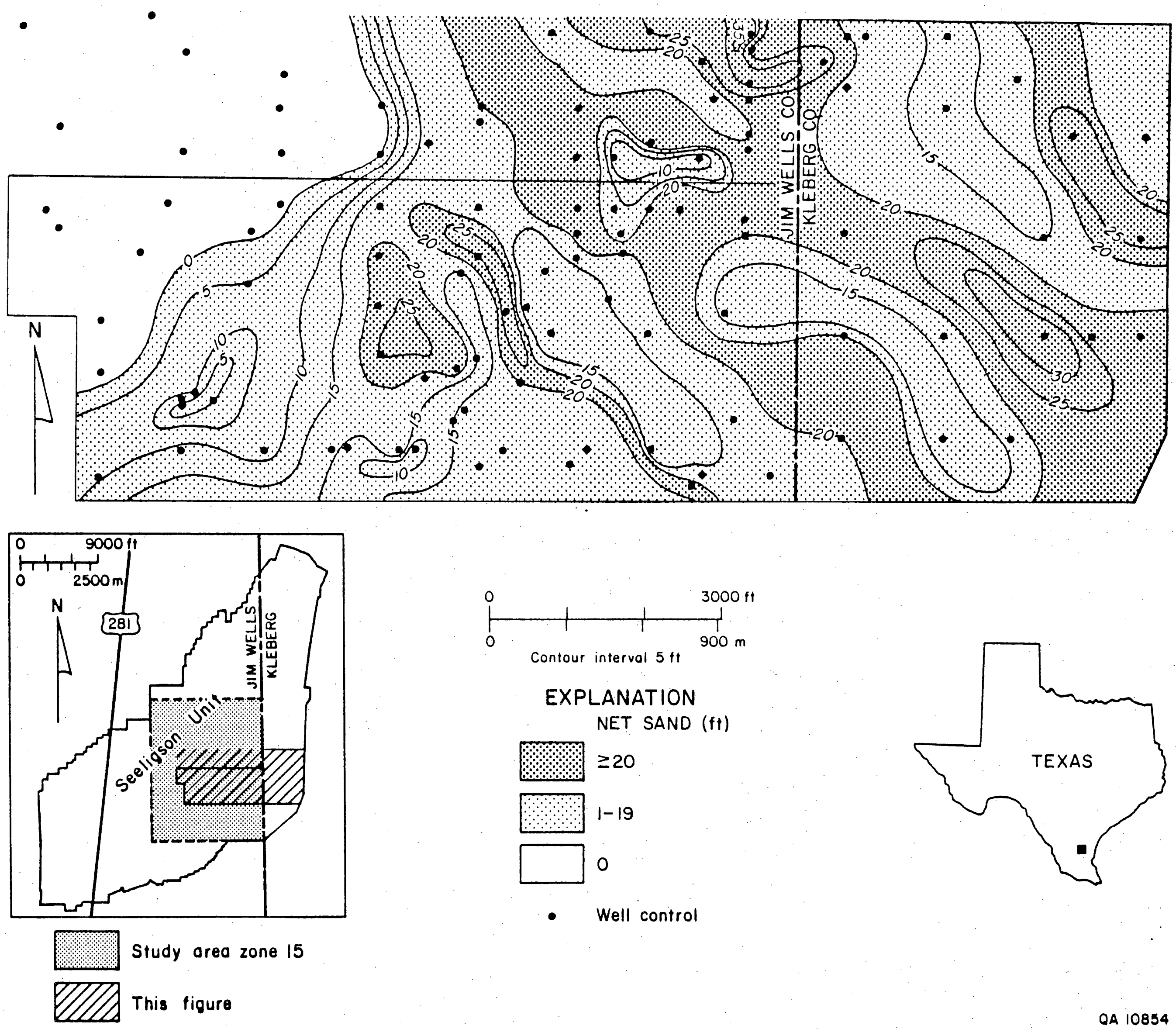

Figure 29. Net-sandstone isopach of Zone 11-B. Dip-parallel depositional trends are typical of fluvial environments in Seeligson reservoirs.

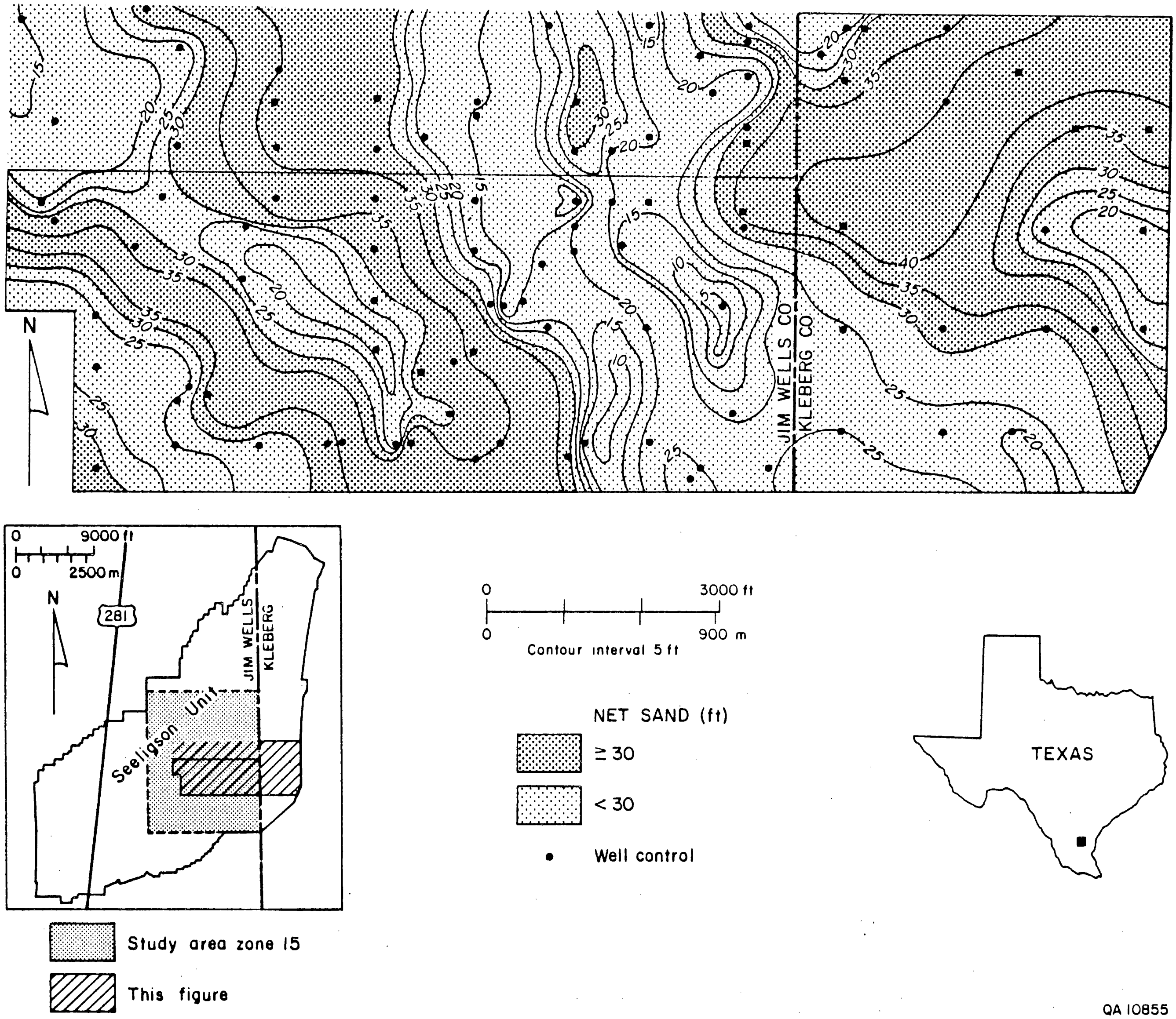

Figure 30. Net-sandstone isopach of Zone 17.

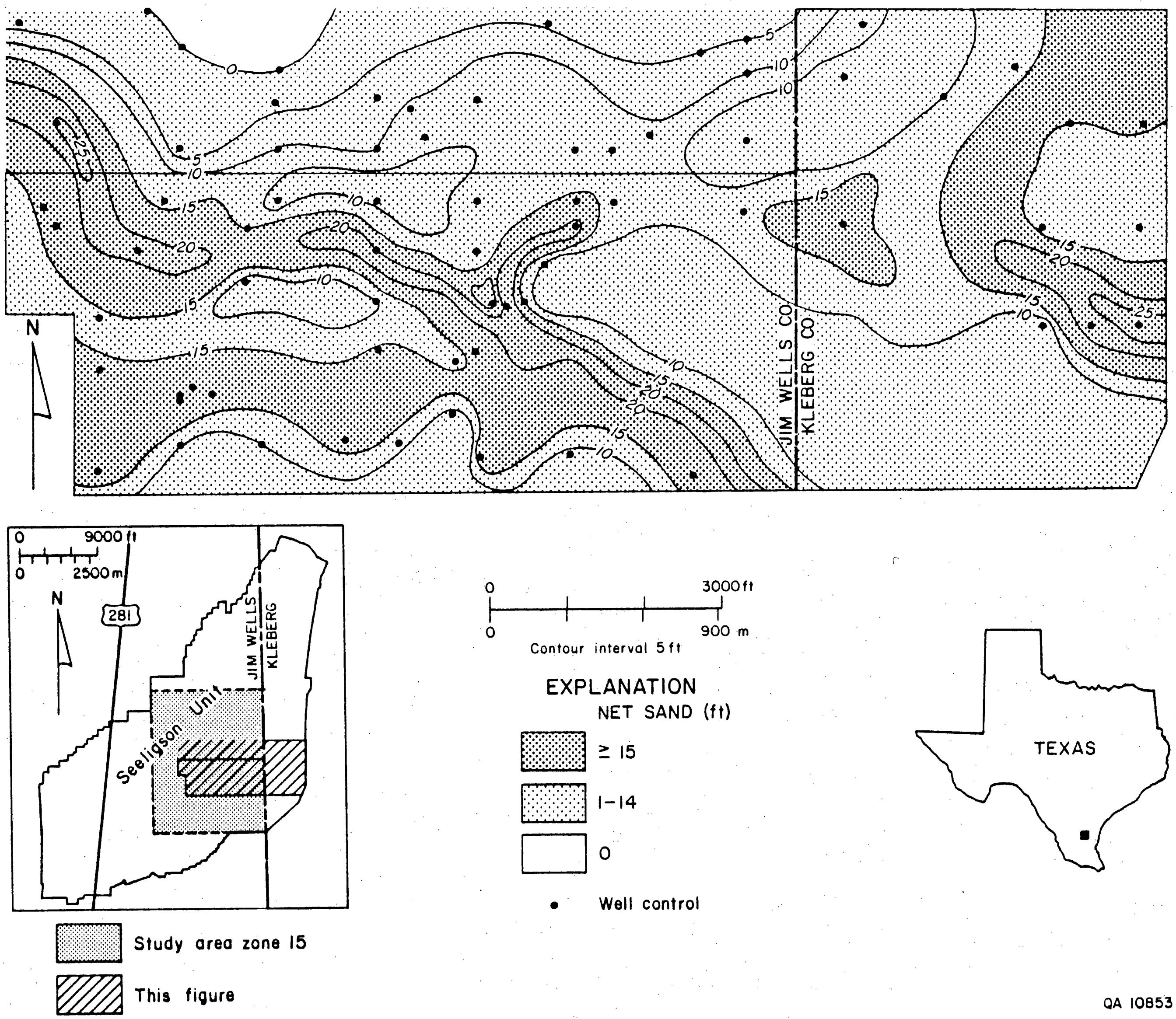

Figure 31. Net-sandstone isopach of Zone 20-B.

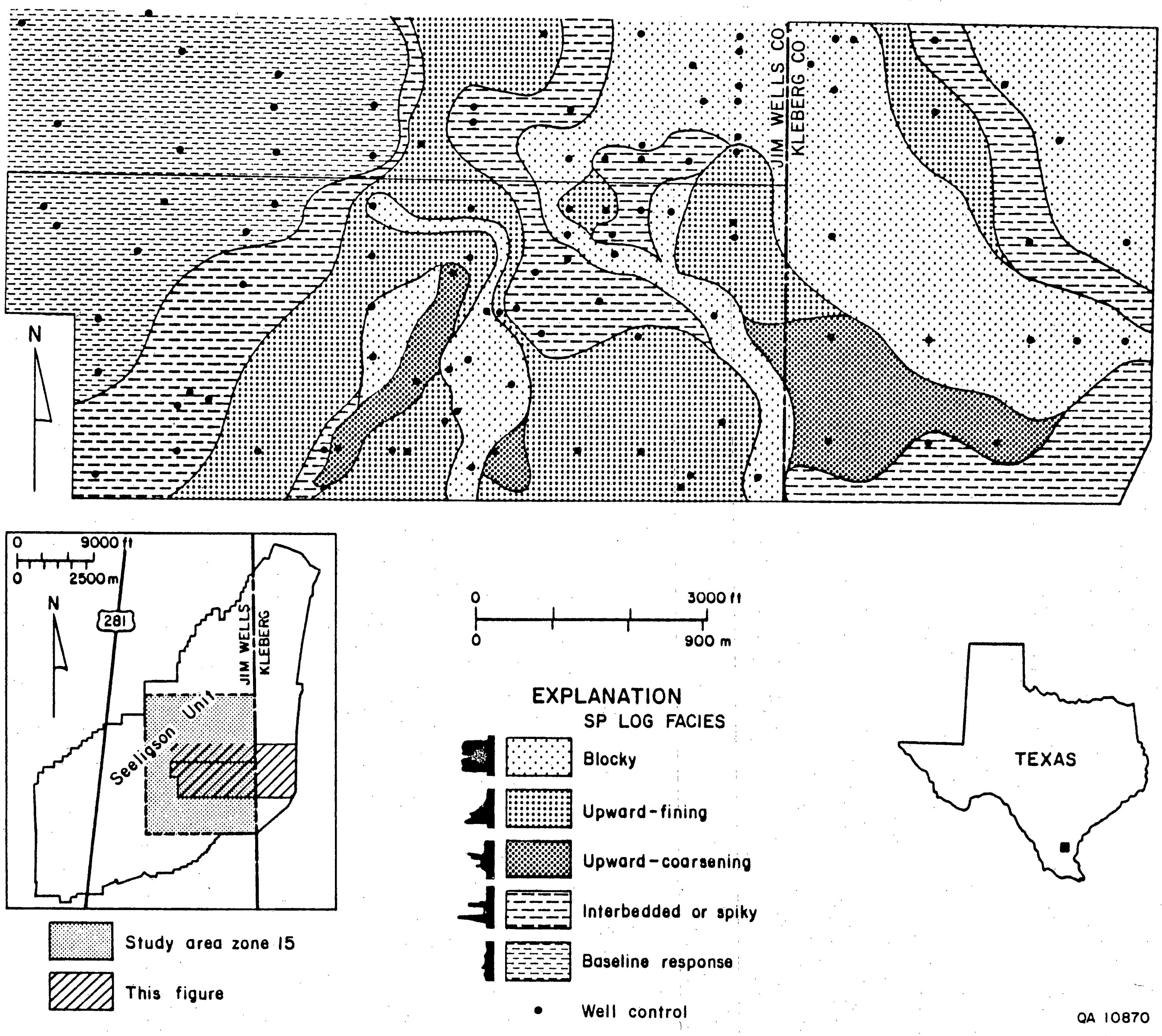

Figure 32. SP log facies of Zone 11-B. Blocky and upward-fining log curve shapes define reservoir-quality channel-fill deposits. Upward-coarsening patterns represent crevasse splay sands; spiky and baseline log responses are indicative of levee-overbank and floodplain facies.

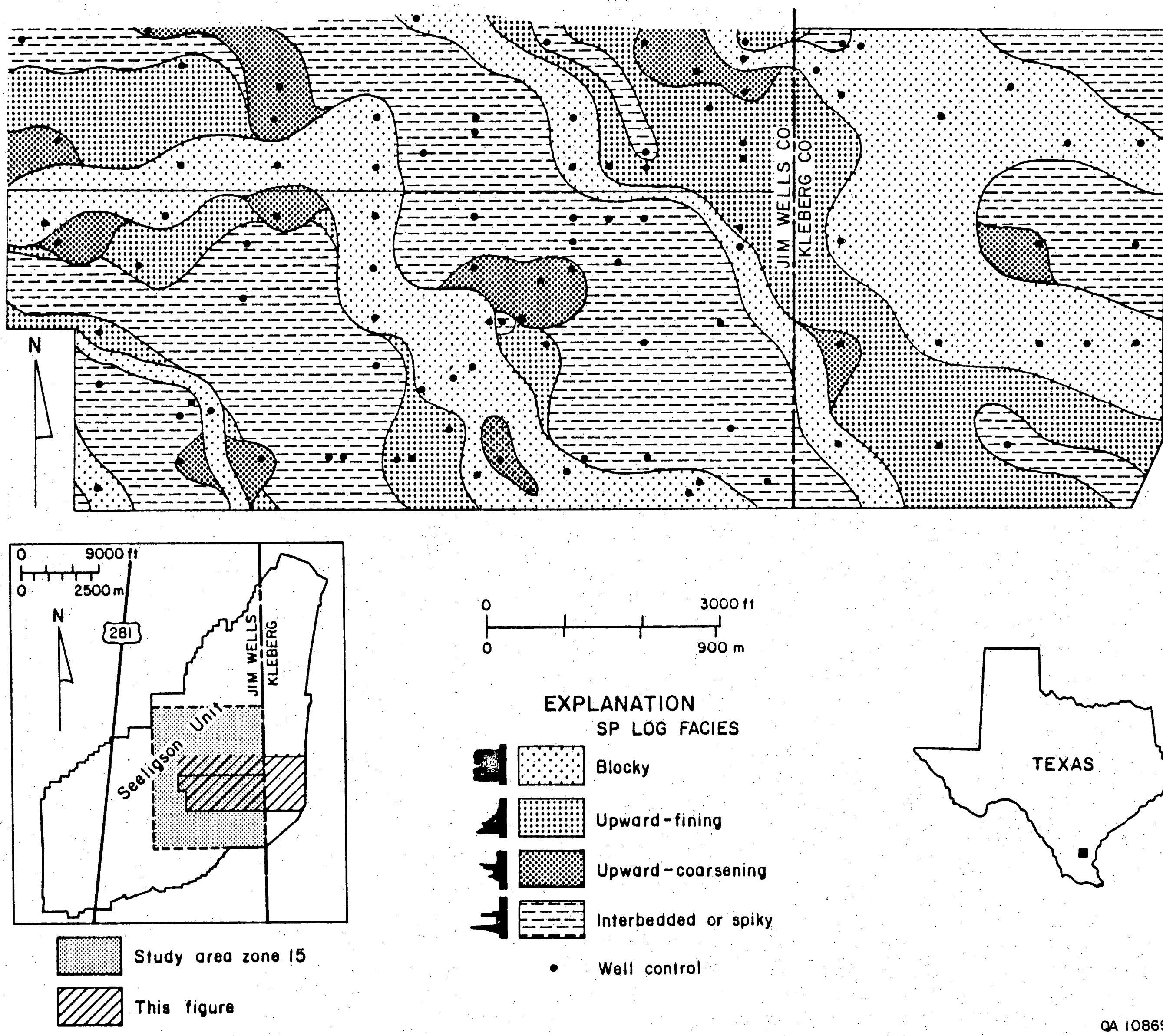

Figure 33. SP log facies of Zone 17.

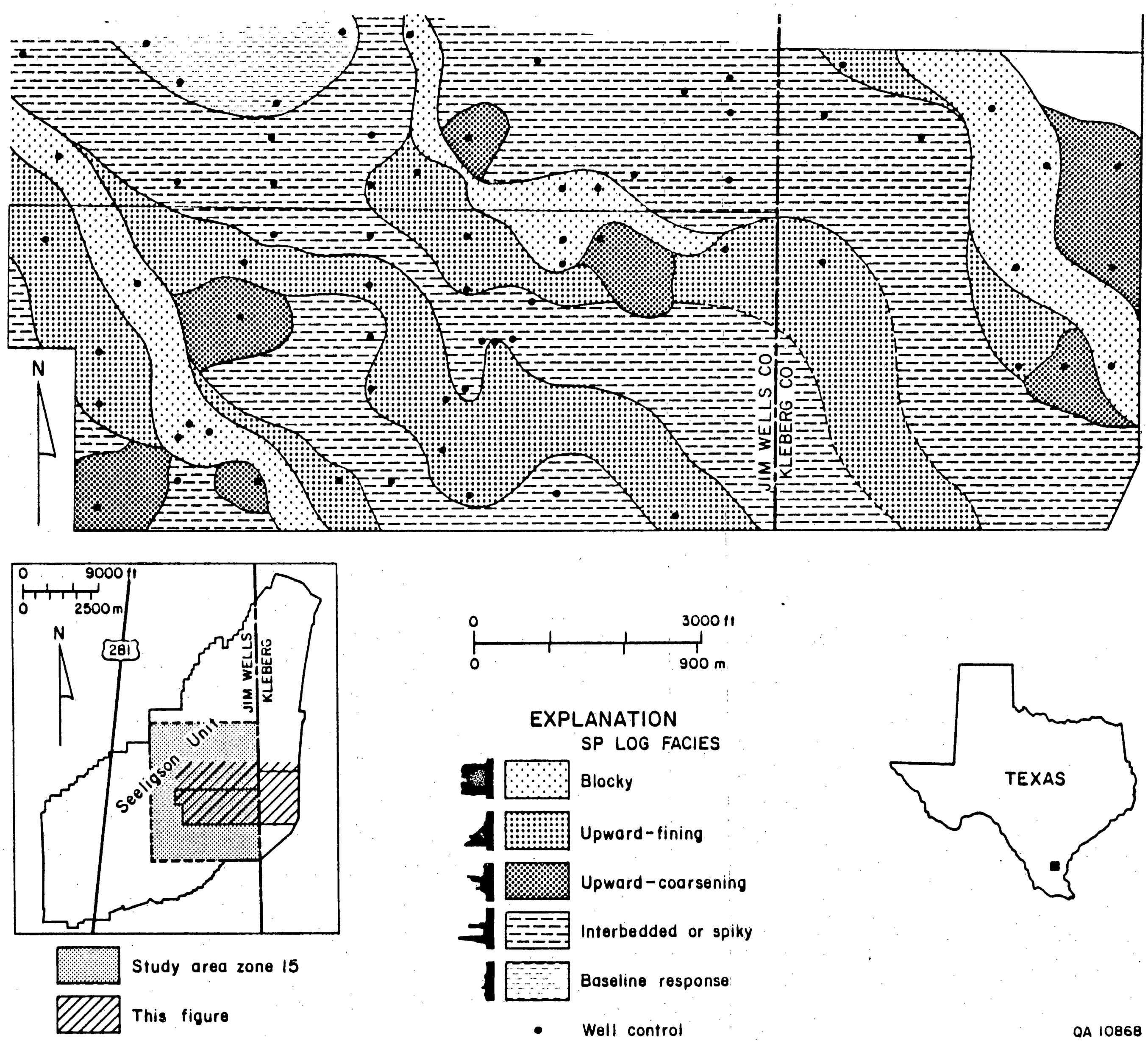

Figure 34. SP log facies of Zone 20-B.

gas shows and inferred bypassed or compartmentalized gas zones; (3) extent of past or current production from zone of interest within the study area; (4) evidence of anomalous BHP's or production histories; and (5) availability of whole core.

Sandstone Heterogeneity

More than 140 Frio and Vicksburg reservoirs have been documented across Seeligson field (Nanz, 1954), and of these, more than 30 Frio reservoirs are productive within the 9-mi^2 detailed study area. These multiple, vertically stacked, dominantly fluvial sandstones exhibit varying degrees of complexity. Although each zone is generally less than 100 ft thick, the majority are composite intervals of several genetic cycles. Aggregate sandstone distribution patterns, as mapped on net-sandstone isopachs within the unit, illustrate dominantly dip-parallel depositional trends generally indicative of fluvial environments (figs. 29, 30, 31). The interbedded sandstones and shales reflect the diversity of the environments of deposition within each zone. Fluvial environments, which include channel-fill, channel margin, overbank, and crevasse splay facies, are characteristically discontinuous and may contain internal permeability differences that tend to segment reservoirs into compartments. These characteristics are favorable for identification of reservoirs that may contain bypassed or compartmentalized gas resources. Regional cross sections and net-sandstone-isopach maps of aggregate Zones 15 and 18-C illustrate these characteristics, and, by having met additional criteria, led to their selection for detailed analysis.

Log Analysis: Indication of Bypassed or Compartmentalized Gas Zones

Analysis of modern logs such as TDT, cased-hole-sonic, pulsed-neutron, and bulk-density logs, was a critical step in evaluating recompletion prospects. Wells having TDT logs were evaluated to determine those with the best potential gas shows. Of those, five were selected for digital cased-hole-sonic logging. Acquisition of cased-hole-sonic data allowed comparison of porosity calculated from TDT logs with porosity calculated from sonic logs to determine gas effect and water saturation (Howard and Bolin, 1988). Old electric logs available for each well were compared with newly acquired sonic data to calculate original open-hole water saturation and to compare it with cased-hole water saturation. Howard and Bolin (1988) presented results of cased-hole log evaluation and identified potential gas productive sands in each of the five wells. Two wells were recommended for recompletion in Zone 15 and one well was recommended for recompletion in Zone 18-C (Howard and Bolin, 1988).

Production History

Seeligson field was discovered in 1937 when the Magnolia A. A. Seeligson No. 7 was drilled to a depth of 8,141 ft, at which point hydrocarbons were encountered in non-unit Zone 22-5. More than 1,000 wells have since been drilled in the field, and cumulative production exceeds 1.3 Tcf from unit reservoirs (D. Sadler, personal communication 1988). Most of the gas is trapped on the crest of the rollover anticlinal structures associated with the major Vicksburg growth fault, although the contribution of stratigraphic controls (sand-body pinch-outs or facies changes) is substantial. Galloway and others (1982) have estimated that stratigraphic features may contribute to trapping in about one-half of the fields within this play. Sun Exploration and Production Company has been evaluating recompletion opportunities in a systematic manner across Seeligson field and has added significant volumes of natural gas to cumulative production totals. Consequently, the need to focus on reservoirs that have had relatively few completions in the study area became apparent. Both Zone 15 and Zone 18-C satisfied this requirement because neither zone has been densely developed within the study area.

Pressure and Production Anomalies

Reservoir heterogeneities or compartmentalization of reservoirs may be indicated where there are significant BHP variations across the field. In addition, production characteristics that deviate from expected results may indicate heterogeneities between wells. Sun Exploration and Production Company engineers identified several reservoirs that they have encountered during their recompletion program with unpredictable drainage histories or anomalous pressure readings. Zone 15 was among those reservoirs cited by Sun as having unpredictable pressures and production irregularities.

Whole Core

Thirty-six feet of whole core from Zone 15 was taken in the Sun P. Canales No. 141 well as part of a cooperative data-acquisition program. The availability of petrographic, core, and SEM analyses, as well as the use of visual description in aiding depositional environment interpretations, made Zone 15 an ideal choice for detailed study.

ZONE 15

General Description

The middle Frio Zone 15 occurs midway through the unitized section at 5,320 ft (log depth) in the 1-24 well (fig. 35). Zone 15 was identified and mapped throughout Seeligson field and has been developed as a homogeneous, continuous reservoir. This study required about 250 electric logs to recorrelate and redefine the stratigraphic framework of Zone 15 in the local area of interest. Highly detailed SP and resistivity correlations reveal that Zone 15 can be subdivided into at least four individual genetic sandstones within the study area, here informally named the 15-A through

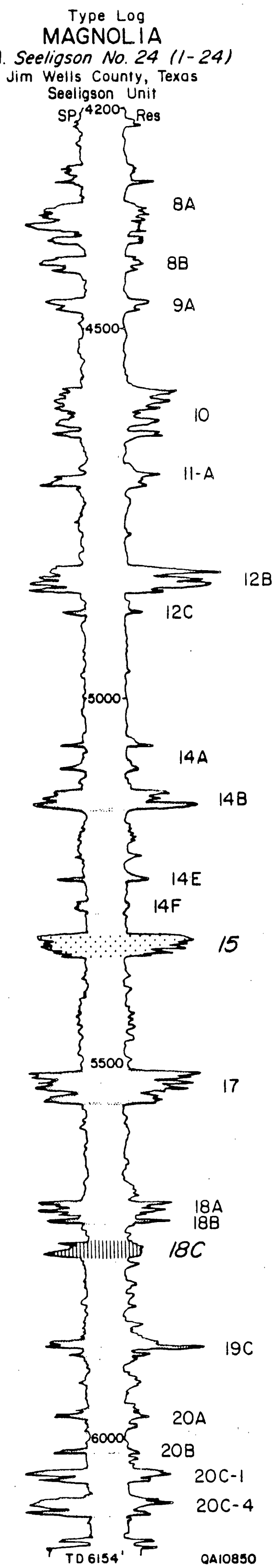

Figure 35. Type log in Seeligson field. More than 20 reservoirs are represented in this well; within the study area more than 30 vertically stacked, dominantly fluvial reservoirs may be encountered. Zones 15 and 18-C were selected for detailed geologic evaluation.

15-D sandstones. The most common stratigraphic occurrence of Zone 15 within the study area is a two-part sandstone body (15-B and 15-C) that is in places separated by a thin (1–5-ft) shale bed (fig. 36). Throughout the study area the zone has different configurations; in the southwestern part, the interval consists of 15-A, B, and C sands coalesced into an amalgamated unit; in other areas, the interval is a relatively thick sandstone that may contain 15-B and C sands without intervening shales, and in several cases only one individual sandstone body comprises the interval (fig. 36). Proponents of standard production and development practices generally overlook this level of interval heterogeneity and therefore bypass opportunities to identify and exploit additional gas resources.

Pressure Anomalies

Of the thirteen wells that have produced more than 57 Bcf of gas from the aggregate Zone 15 within the study area, BHP's from 11 (fig. 37) were plotted against time (fig. 38). Significant deviations above the curve are found in recently completed wells 16-97, 16-124A, 42-67 and P. Canales No. 141, where BHP's are in the 1,100- to 1,200-psi range. These anomalous pressures were considerably higher than the expected low BHP's of 300 to 500 psi. These low BHP's reflect more than 35 yr of production, which has depleted the reservoir pressure. Detailed geologic evaluation of reservoir facies indicates that wells falling on the decline curve are concentrated in an area within about 1 mi of each other in channel-fill and channel-margin deposits in the north-central and northwest part of the area (fig. 38). Wells 1-225, 1-114, 1-98, and 1-163 lie within a major channel-fill complex and most likely drain the same reservoir. Well 17-1 lies in a proximal splay deposit that is attached to the major channel complex, apparently draining the same reservoir. Farther to the west, wells 1-157, 1-47, 1-160 lie in an adjacent channel-fill complex that may be separated from the central channel by finer grained levee-overbank deposits, although reservoir pressures indicate that there is good communication between the two channel complexes. The four wells that show BHP's above the decline curve (fig. 38) are located in the southwestern part of the

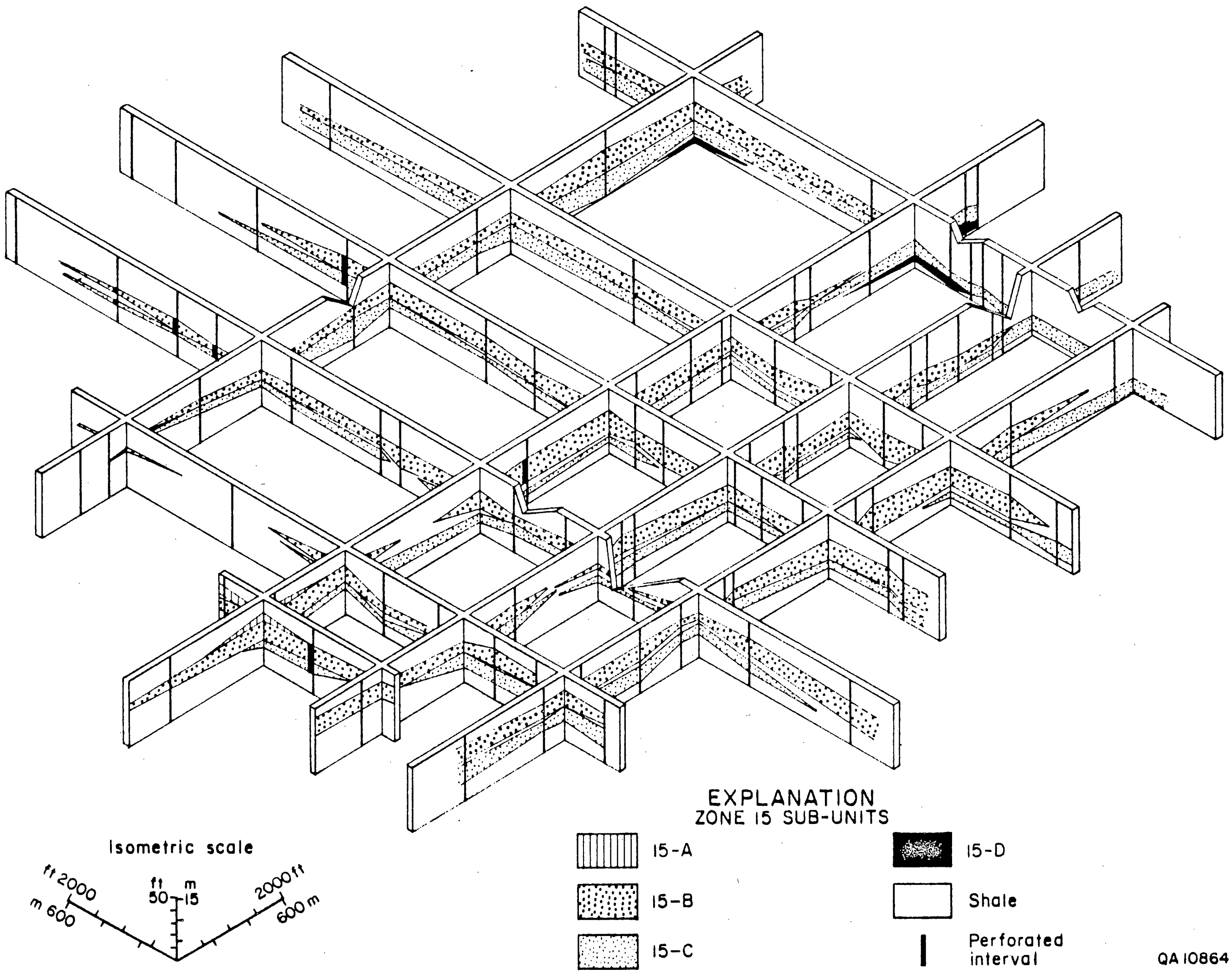

Figure 36. Fence diagram of Zone 15. The reservoir has been subdivided into four component genetic sandstones, 15-A through 15-D. Sands 15-B and 15-C have the greatest distribution within the area of interest and are frequently vertically isolated by a thin shale bed. Refer to figure 37 for location.

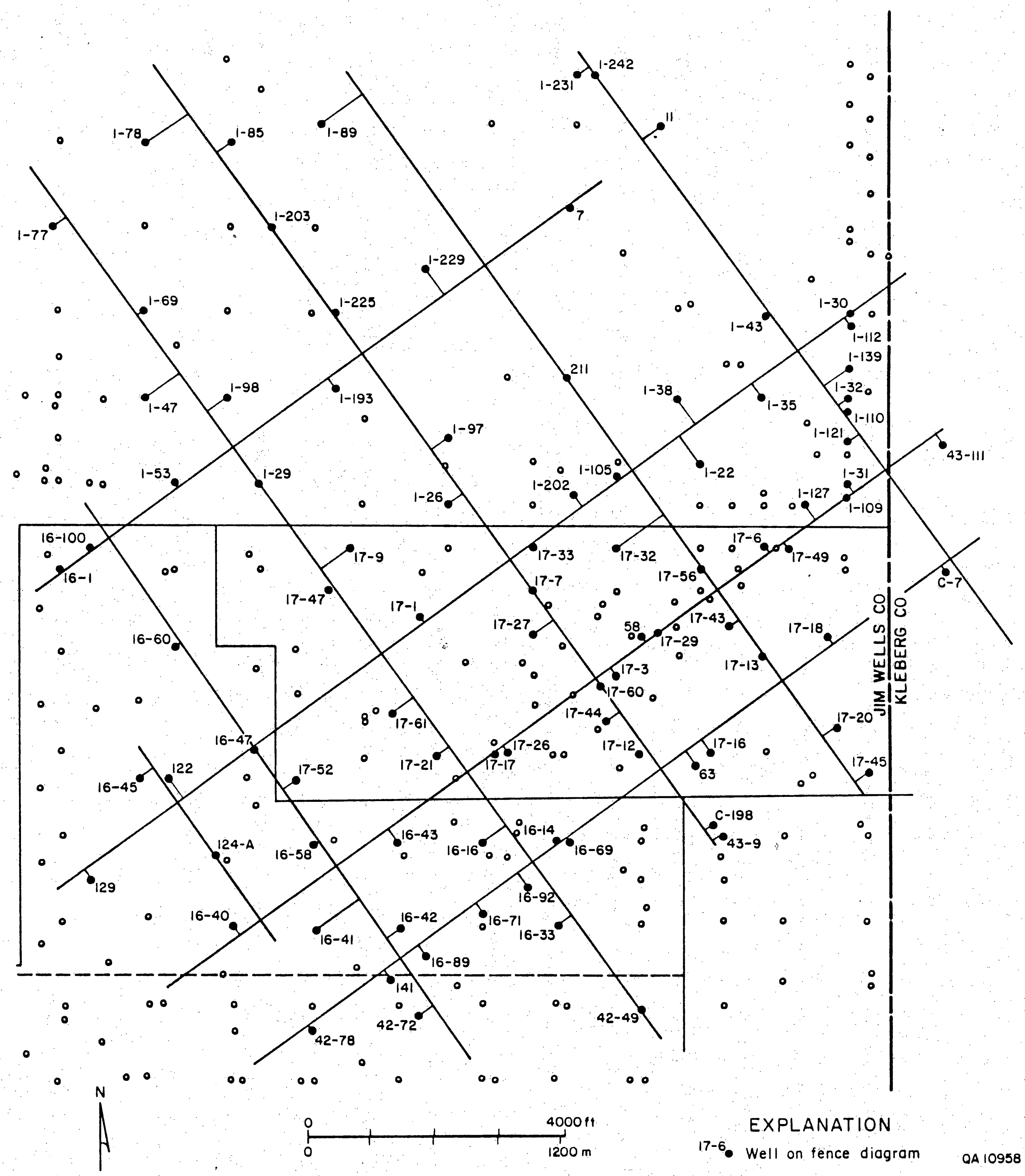

Figure 37. Location of wells in fence diagram. Fence diagram shown in figure 14.

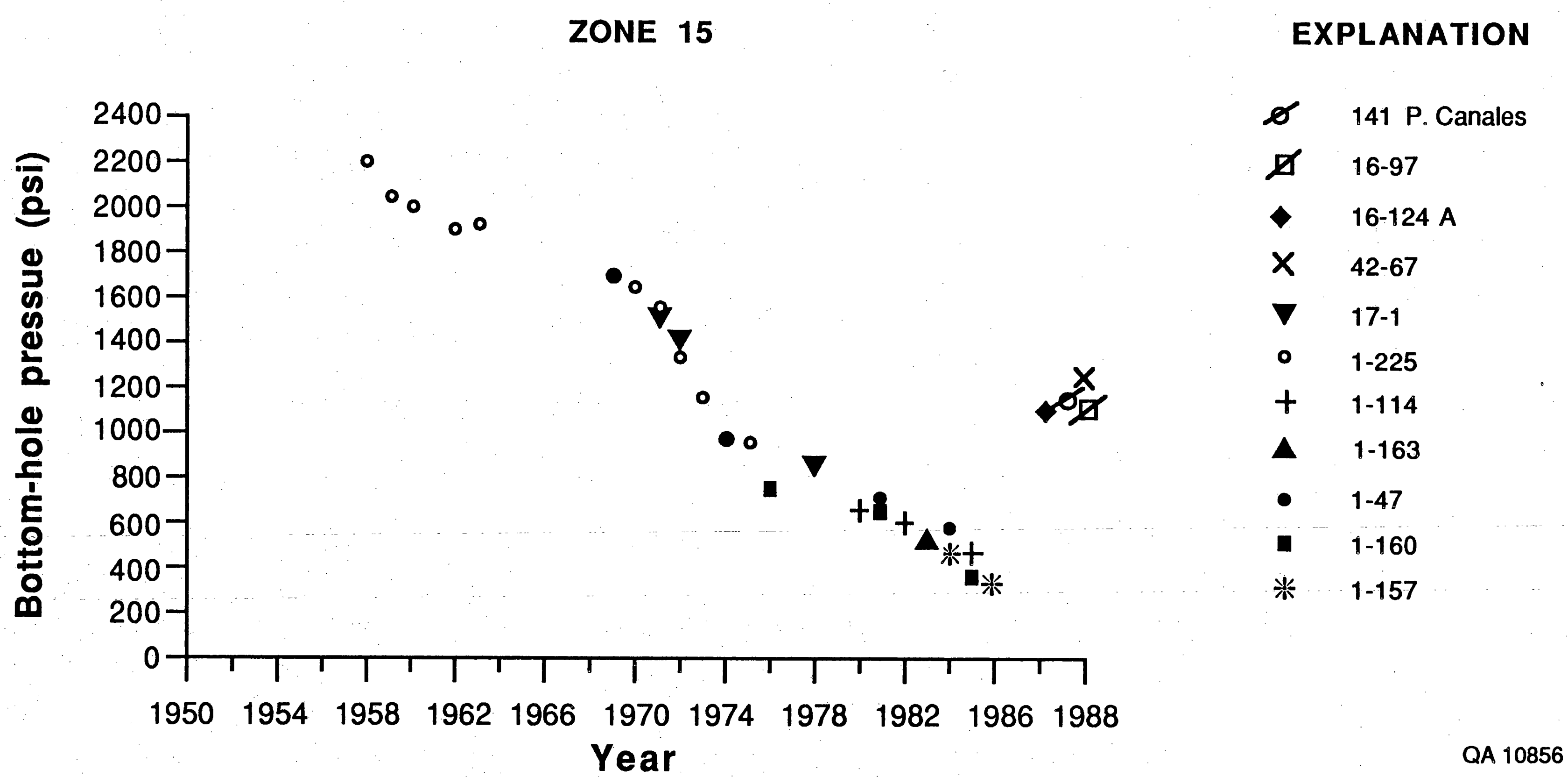

Figure 38. Bottom-hole pressure versus time for 11 wells productive in Zone 15 (data from Sun Exploration and Production, Inc.).

study area, approximately 1 mi from the wells described above. The salient geological feature separating the group of higher pressure wells from those with depleted pressures is a tongue of floodplain mud that averages 2,000 ft in width and extends about 1 mi into the area before grading into overbank deposits. Muddy facies recur in a small area 2,500 ft farther downdip between the channels. Three of the wells (16-97, 16-124A, and P. Canales No. 141) are found in the same channel-fill deposit; the fourth (42-67) occurs in another channel-margin sandstone (fig. 39). The fact that four wells have BHP's significantly higher than expected in a depleted reservoir can be explained geologically by their location in channel-fill complexes horizontally separated from the depleted reservoirs of a different channel complex by muddy floodplain facies. The floodplain mudstones provide an adequate permeability barrier that restricts flow and isolates at least two separate reservoirs that had previously been assumed to be a single, homogeneous reservoir.

DETAILED GEOLOGIC EVALUATION

Zone 15-B

Sandstone Distribution

Zone 15-B sandstones exhibit predominantly dip-elongate net-sandstone patterns typical of fluvial environments. Net-sandstone thickness across the study area ranges from 2 ft to 20 ft with high net-sandstone areas forming elongate, dip-parallel belts of channel-fill facies. Two primary depositional axes appear within the study area; the greatest concentration of sandstone occurs in the east-central and southwest areas, which are divided by a narrow tongue of shale. In the southeast corner of the area the axes converge to form a relatively broad, dip-aligned belt of sandstone (fig. 40). The contour patterns suggest that areas of high net-sandstone values, particularly where they align in subparallel belts, represent areas of channel-fill deposits, and lobate or isolated thicks may represent overbank or proximal crevasse splay facies. Low net-sandstone values (1 to 10 ft) are

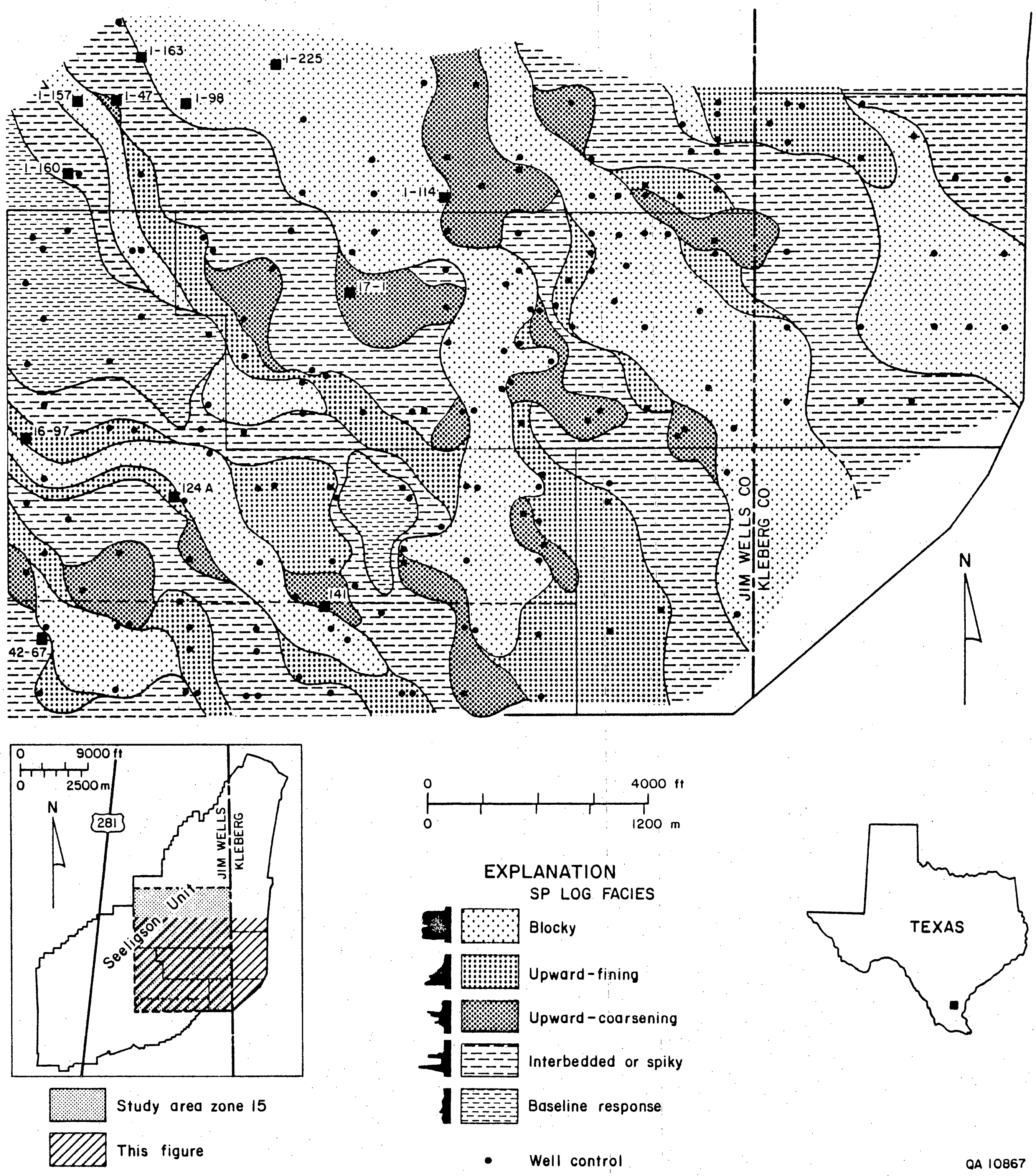

Figure 39. SP log facies map of aggregate Zone 15. Two major channel complexes are separated by a tongue of floodplain silts and muds. Anomalously high bottom-hole pressures were noted in recompleted wells located in the southwestern channel complex.

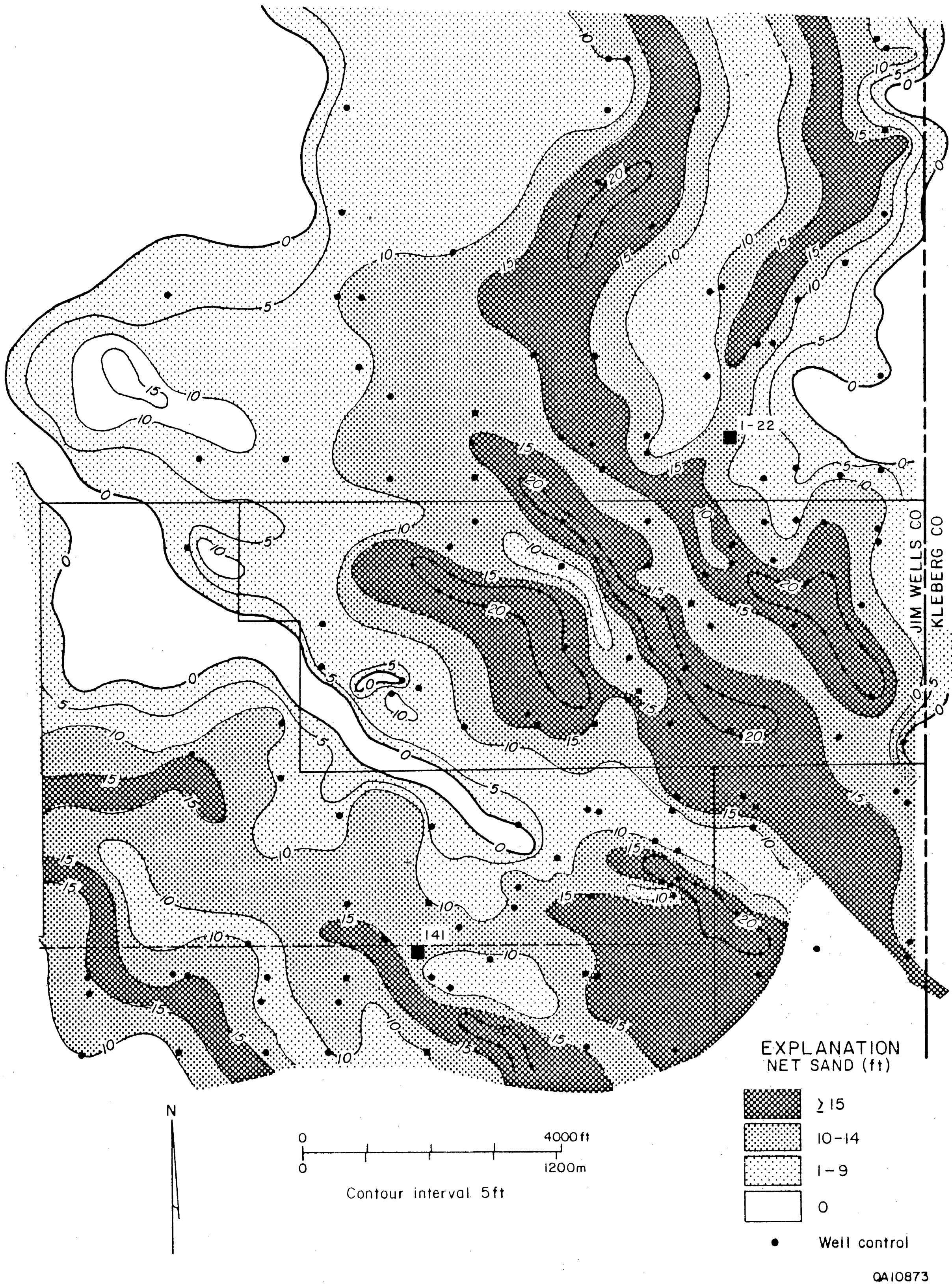

Figure 40. Net-sandstone isopach of Zone 15-B. Primary depositional axes occur in the east-central and southwest part of the area. Note the tongue of shale separating the principal depocenters.

indicative of channel-margin environments and levee or overbank deposits. Zero-sandstone areas are occupied by broad, muddy floodplains and interchannel mudstones or muddy abandoned-channel deposits.

Depositional Environment

SP log-facies mapping uses representative SP curve shapes to characterize depositional environments. SP log responses of Seeligson field (and South Texas Frio) channel-fill and point-bar sandstones are generally blocky and sharp based. Point-bar sands may also display crude upward-fining patterns (Galloway, 1977). Another log response typical of channel-fill sandstones is a blocky serrate pattern, representative of shale interbedding among stacked channel-fill sandstones. Crevasse splay deposits may be characterized by upward-coarsening log patterns as well as by the patterns described for channel-fill sandstones, although individual beds may be thinner. Overbank and levee deposits are characterized by thin, spiky log responses, and silty and muddy floodplain deposits are represented in baseline responses.

Log-facies maps illustrate environments typical of South Texas Frio fluvial systems. Channel-fill facies, flanked laterally by overbank splay and levee deposits, course through the study area from northwest to southeast (fig. 41). Channel widths are generally less than 1 mi; most average about 2,000 ft. Crevasse splay facies attached to channels are numerous throughout the area. Thin levee and overbank deposits occur between channels and merge with floodplain mudstones to the west and southwest (fig. 41).

Interpretation of Zone 15 depositional environments was aided by the availability of whole core from the Sun P. Canales No. 141 well. The cored interval (5,406–5,442 ft) includes 27 ft of sandstone and 9 ft of shale from Zone 15. Core recovered from Zone 15-B consists of 8.5 ft of very fine to fine-grained sandstone (the complete interval is interpreted to be 14 ft thick on the basis of the triple combo log; 10 ft of the interval was cored, 1.5 ft not recovered). Cored 15-B sandstones coarsen upward slightly through the first 2 ft, then maintain a constant to slightly upward-fining

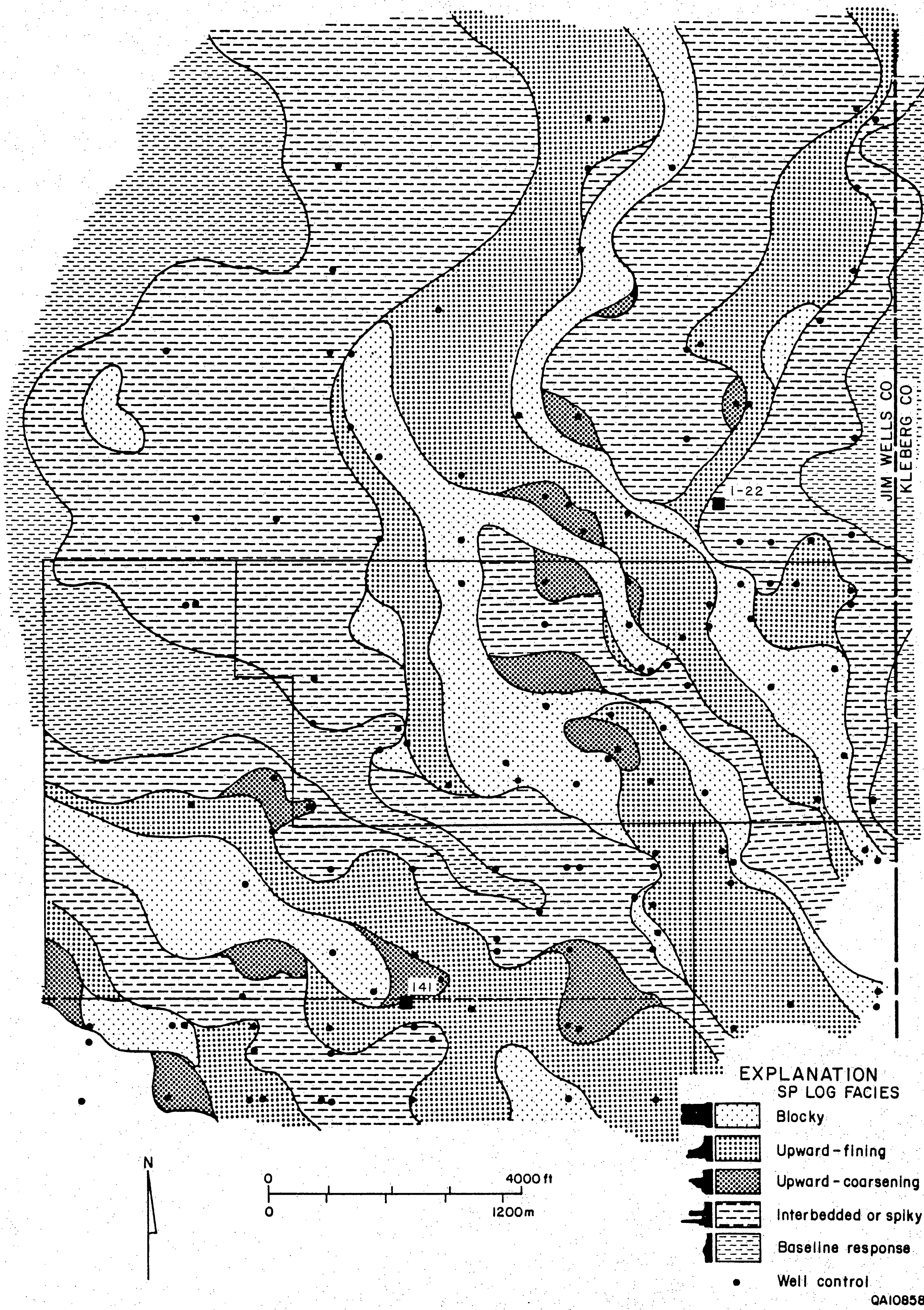

Figure 41. SP log facies map of Zone 15-B. Fluvial channels, crevasse splays, natural levee and overbank deposits, and interchannel floodplain muds are represented in this interval.

grain size through the next 6 ft. The upper 4 ft (which was not cored), displays an upward-fining pattern based on log interpretations. Overall, grain-size variations are minor, ranging from fine to very fine sand. Horizontal to slightly inclined laminations are observed, and flattened shale clasts occur at an erosional scour surface. Whole-core analyses indicate sandstone porosities in the 19- to 22-percent range, permeabilities ranging from 61 to 270 md. This interval is interpreted as a lower point-bar deposit.

Zone 15-C

Sandstone Distribution

Zone 15-C sandstones exhibit predominantly dip-oriented patterns typical of fluvial environments. Net-sandstone values range from 2 to 20 ft and high net-sandstone areas are concentrated primarily in elongate belts of sediment less than 1,000 ft wide (fig. 42). Four principal 15-C depositional axes transect the study area but do not locally converge. The 15-C sandstone pinches out to the west into a broad floodplain, and several isolated shale-outs (abandoned-channel mud plugs?) occur around and between depositional axes (fig. 42). In contrast to the distribution of overlying 15-B sandstones, 15-C sandstones are thinner and were deposited in narrower bands. In several areas, both 15-B and 15-C sandstones occupy the same depositional axis, although channel migration or abandonment is suggested in areas where 15-B sandstones overlie muddy or silty facies of the 15-C interval.

Depositional Environment

SP log-facies mapping of the 15-C interval (fig. 43) illustrates blocky, sharp-based SP log patterns that define narrow (less than 1,000 ft) channels winding through the study area in a northwest-southeast direction. These channel-fill and point-bar sandstones, which are also

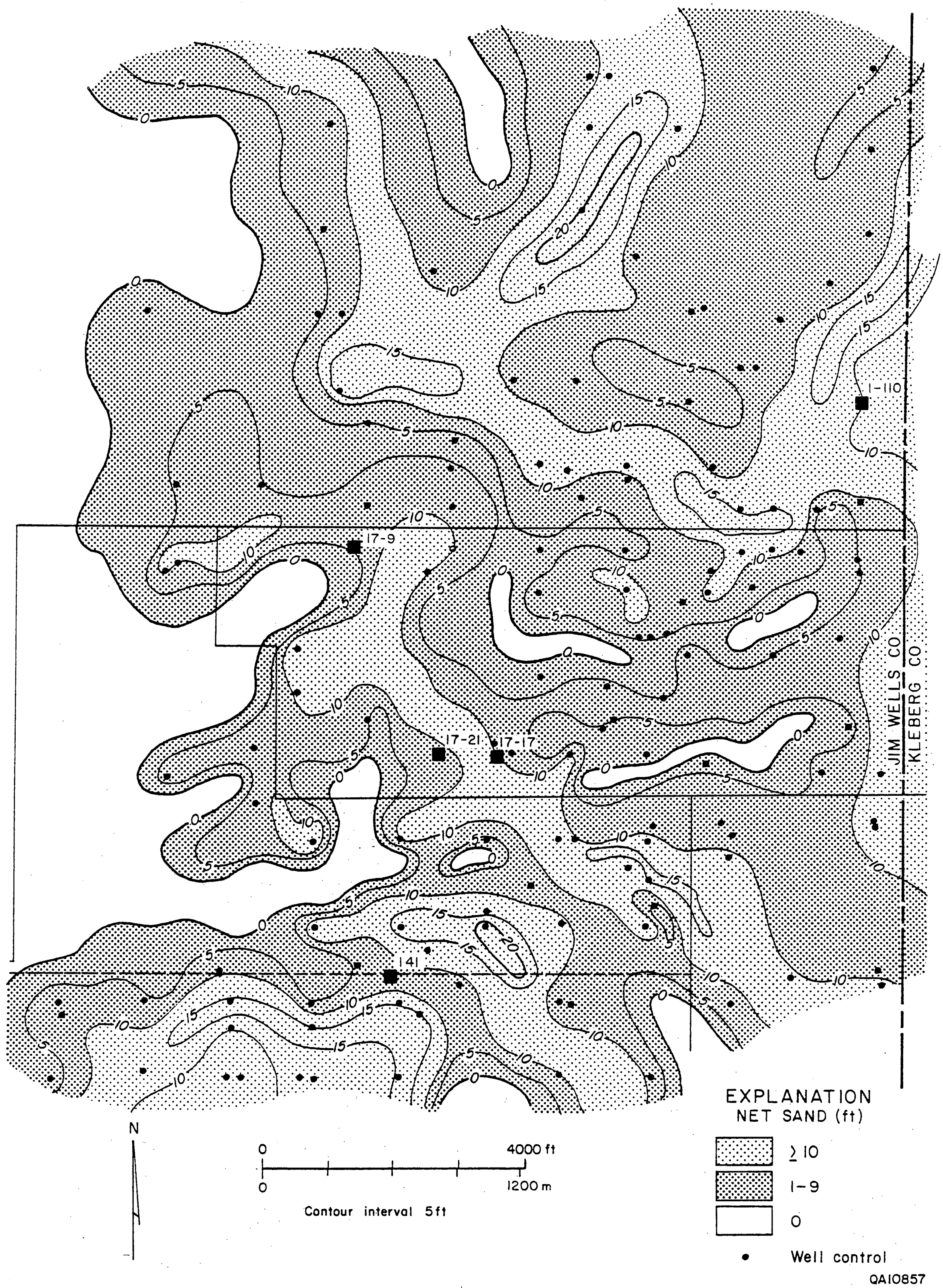

Figure 42. Net-sandstone isopach of Zone 15-C. Primary depositional axes occur in the northeastern, central, and southwestern parts of the area. Sandstones pinch out in several localized areas and near the western edge of the study area.

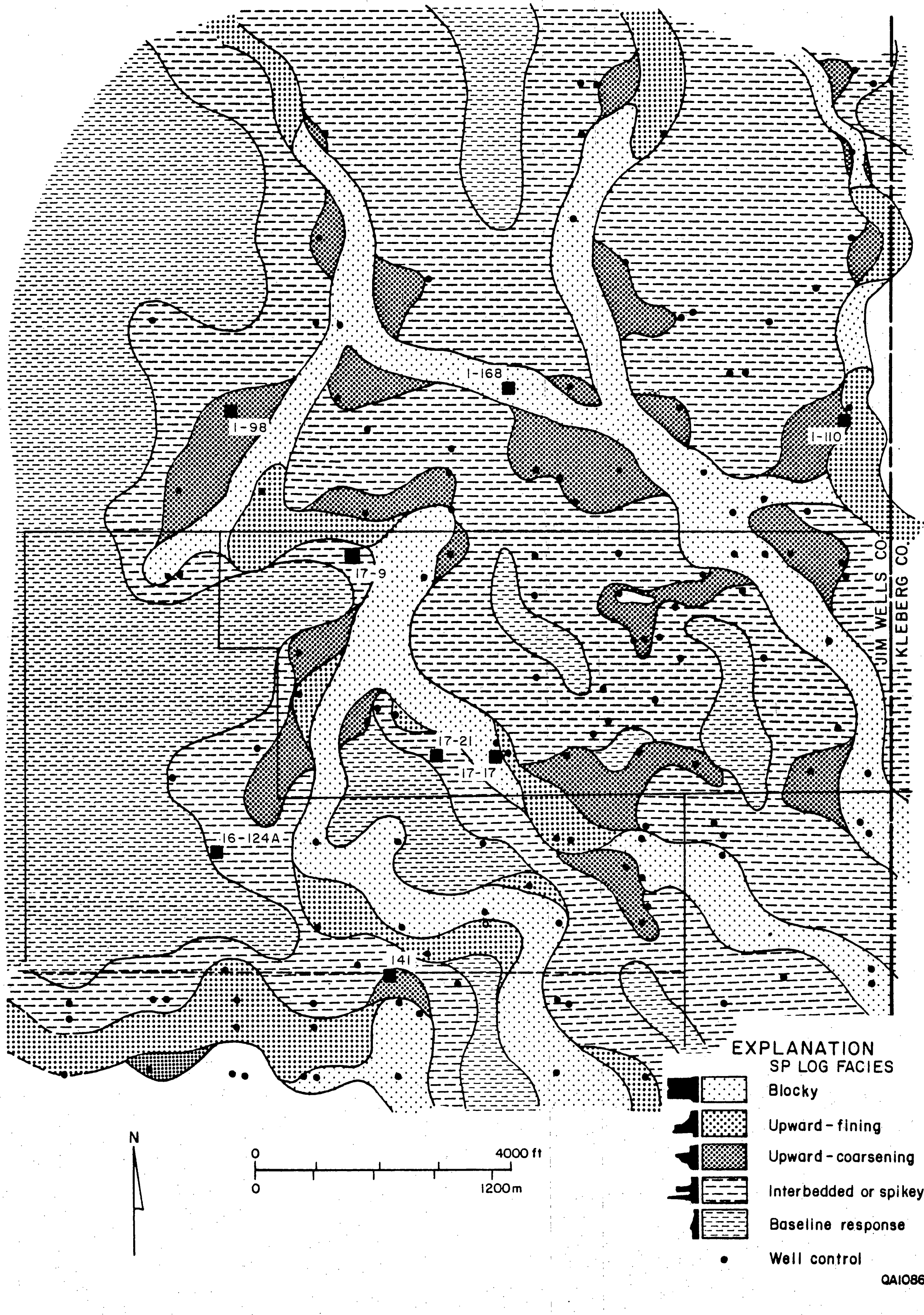

Figure 43. SP log facies map of Zone 15-C. Crevasse splay deposits are more widespread than in Zone 15-B. Localized muddy areas may represent mud plugs in abandoned channels.

characterized by upward-fining SP responses, are flanked by relatively broad lobes of upward-coarsening crevasse splay deposits. Widespread, well-developed splay sandstones are more common here than in overlying Zone 15-B and are typical of Gueydan fluvial-streamplain environments (Galloway, 1977). Spiky SP curves delineate levee and overbank deposits that form broad, fine-grained interchannel aprons. A broad, muddy floodplain (baseline SP response) covers the western one-fourth of the study area, and several locally muddy areas may represent mud plugs occupying abandoned channels (fig. 43).

Whole core taken in Zone 15 from the Sun P. Canales No. 141 includes 10 ft of sandstone and siltstone that comprise the 15-C interval. The base of the sandstone at 5,428 ft (core depth) is defined by an erosional scour surface with gravel-size rip-up mud clasts. Horizontal to slightly inclined laminations with possible crosscutting and minor scour surfaces are observed in the first 3 ft of the medium-grained sandstone, which has porosity values of 11 to 21 percent and permeabilities of 3 to 400 md. These features are interpreted to have been formed in a proximal crevasse splay environment. Climbing ripples occur at 5,424.5 to 5,425.2 ft, which are followed by abundant thin, horizontally bounded beds of very fine sandstone with silt drapes. The remaining 5 ft of core is characterized by slightly upward-coarsening medium-grained sandstone with rare flattened clay clasts and faint horizontal laminations. Porosity ranges from 21 to 27 percent and permeabilities 400 to 1,100 md in this interval. Overall, interpretations made from the 10 ft of 15-C core indicate proximal splay and splay channel environments of deposition.

Zone 18-C

General Description

Zone 18-C occurs at 5,733 ft on the type log (fig. 35). This middle Frio sandstone is the lowest reservoir within the three-part Zone 18 interval.

The detailed study area for Zone 18-C differs somewhat from the Zone 15 map area; the northern and southern boundaries are cropped, and the eastern boundary has been extended into Kleberg County. The principal reason for this modification is the restricted development of the 18-C sandstone throughout the area of interest. Zone 18-C sandstone occurs principally in the northern half of the area and trends in a west-to-east direction (fig. 44). More than 50 electric logs were used to update the stratigraphic framework of the 18-C interval, and three cross sections were constructed to illustrate lateral relationships of producing and prospective reservoirs. Detailed SP and resistivity correlations identify an interval composed of two individual genetic sandstones, separated locally by a thin shale bed and coalescing in other areas to form a single sandstone unit (fig. 45). For purposes of this study, the two stratigraphic subunits of Zone 18-C are informally named the 18-C upper and the 18-C lower.

Production

Gas production from the 18-C reservoir throughout Seeligson field totals 22 Bcf from eight wells. Within the area of interest, only one well has produced from the 18-C, well 1-168, with cumulative production totaling just over 660 MMcf. The primary trapping mechanism, as in Zone 15 sandstones, is structural; gas is produced from the crest of rollover anticlinal structures formed on the downthrown side of the major Vicksburg fault. However, because of the limited distribution of 18-C sandstones within the study area, the occurrence of localized structural highs and pinch-outs of the sandstone (stratigraphic traps) is of paramount importance during a search for traps.

Sandstone Distribution

Aggregate Zone 18-C sandstones range from 2 to 32 ft in thickness across the study area. Overall distribution of sandstone runs primarily from west to east, the sandstones pinching out to the north and south, forming a ribbon of sand approximately 1 mi wide. A narrow zone of northeast

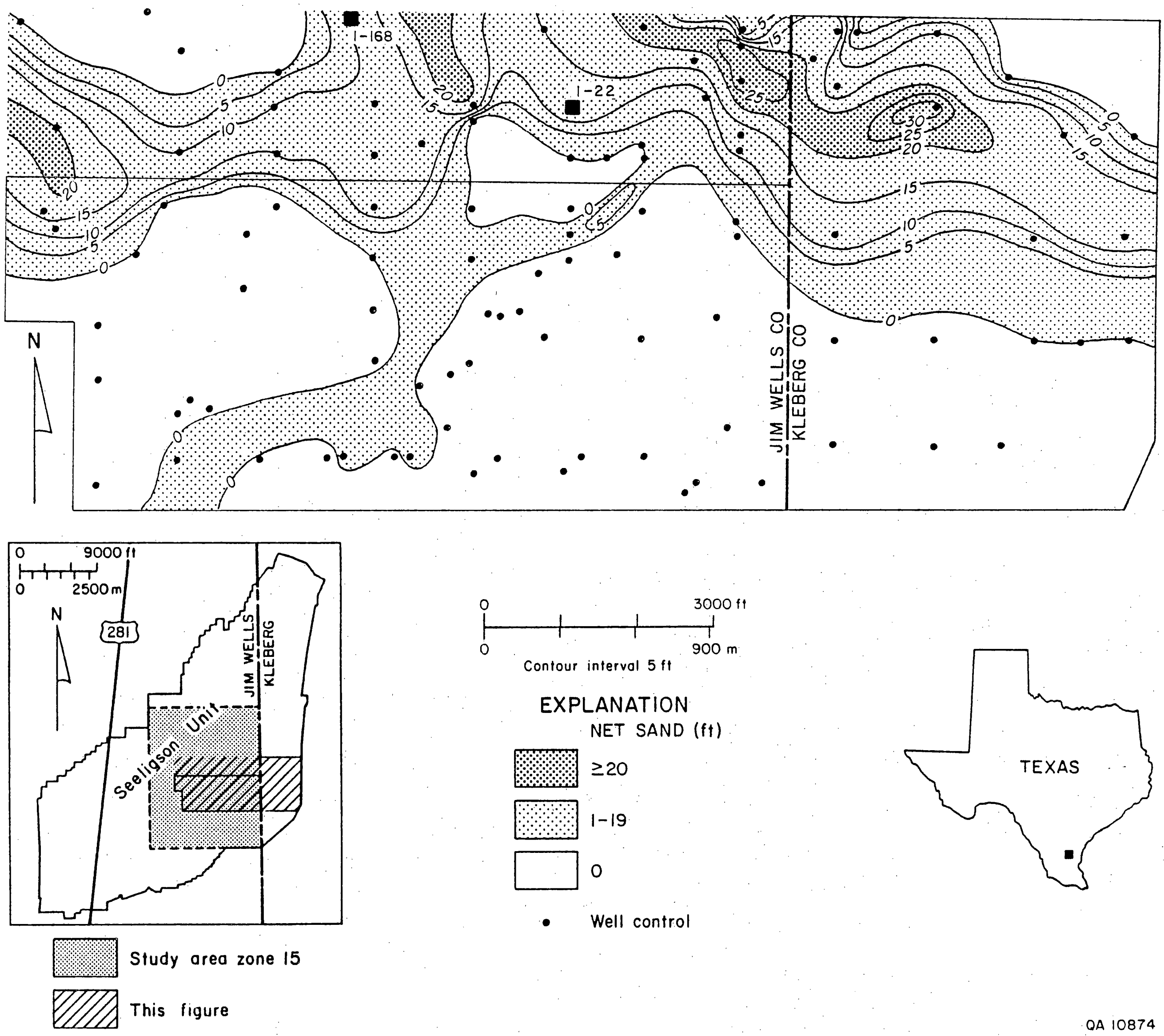

Figure 44. Net-sandstone isopach of aggregate Zone 18-C. Sandstone thicks (>20 ft) are found in dip-aligned pods and indicate primary axes of deposition.

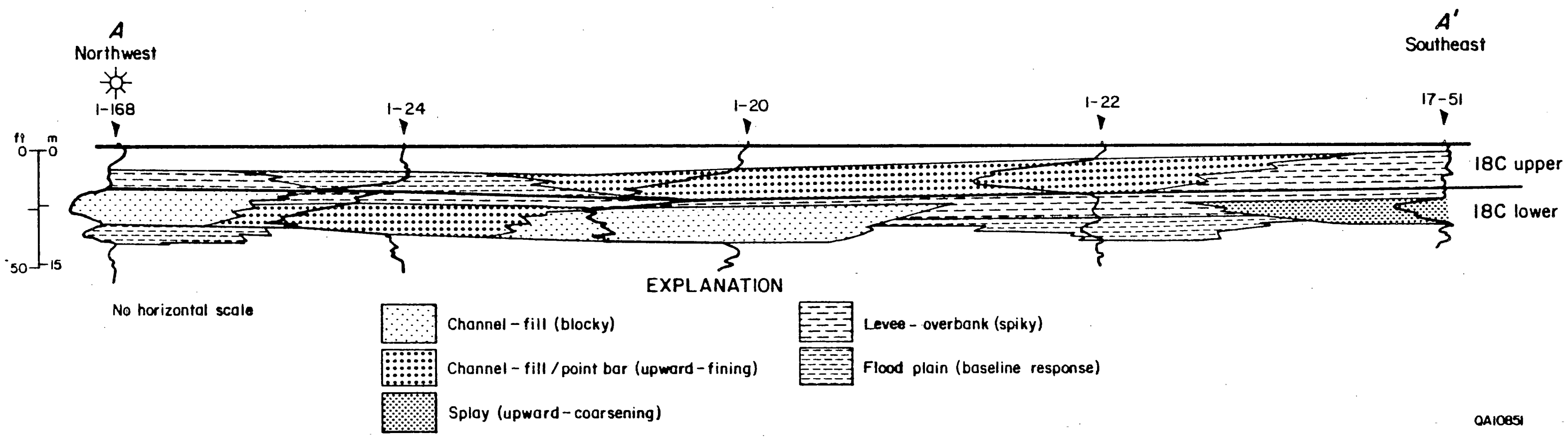

Figure 45. Stratigraphic cross section A-A' illustrating upper and lower sandstones within Zone 18-C (see fig. 46 for location). Recompletion target is channel-fill/point-bar sandstone of 18-C upper in well 1-22. Facies changes in both upper and lower units should compartmentalize 18-C lower reservoir in well 1-168 and isolate potential gas-bearing 18-C upper zone in well 1-22.

to southwest trending, very thin (less than 3 ft) sandstone intersects the main depositional axis in the central part of the study area (fig. 44). Net-sandstone highs are concentrated in roughly three subparallel, dip-oriented elongate beads, suggesting deposition in fluvial channel environments.

Sandstone distribution patterns vary in the 18-C upper and lower component sandstones. The 18-C lower sandstone follows the same trend and occupies nearly the same width as the aggregate unit, although net-sandstone values are less, ranging from 2 to 22 ft. The net-sandstone contours are aligned in a west-to-east trending band with four separate, arcuate pods outlining the principal areas of deposition (fig. 46). Net-sandstone patterns of this type are characteristic of point-bar and channel-fill sandstones in mixed-load fluvial systems (Galloway, 1977).

The 18-C upper sandstone belt, while following the same west-to-east trend, occupies a narrower area than the underlying 18-C lower sandstone (fig. 47). Throughout the west and central portions of the study area the belt rarely exceeds 1,500 ft; only in the eastern part of the area does the width of the belt approach 4,000 ft. Net-sandstone thicknesses range from 1 to 20 ft, and areas of greatest sandstone thickness are concentrated in arcuate-shaped beads typical of point-bar and channel-fill sandstones (fig. 48).

Depositional Environment

Zones 18-C lower and 18-C upper each consist of single, narrow, fluvial channels trending west to east through the study area. Sharp-based, blocky and upward-fining log responses define the axis of the channel-fill deposits; in the 18-C lower sandstone, the width of the axis is approximately 1,000 ft and is continuous through the area. Channel-margin deposits (spiky log responses) are very narrow and grade into floodplain siltstones and mudstones (baseline log response). Zone 18-C upper facies are similar to those of 18-C lower, although channel-fill and point-bar deposits are narrower and are found in discrete pods rather than in a continuous belt. As in the 18-C lower, the channel axis is bordered by narrow channel-margin deposits that grade into floodplain mudstones.

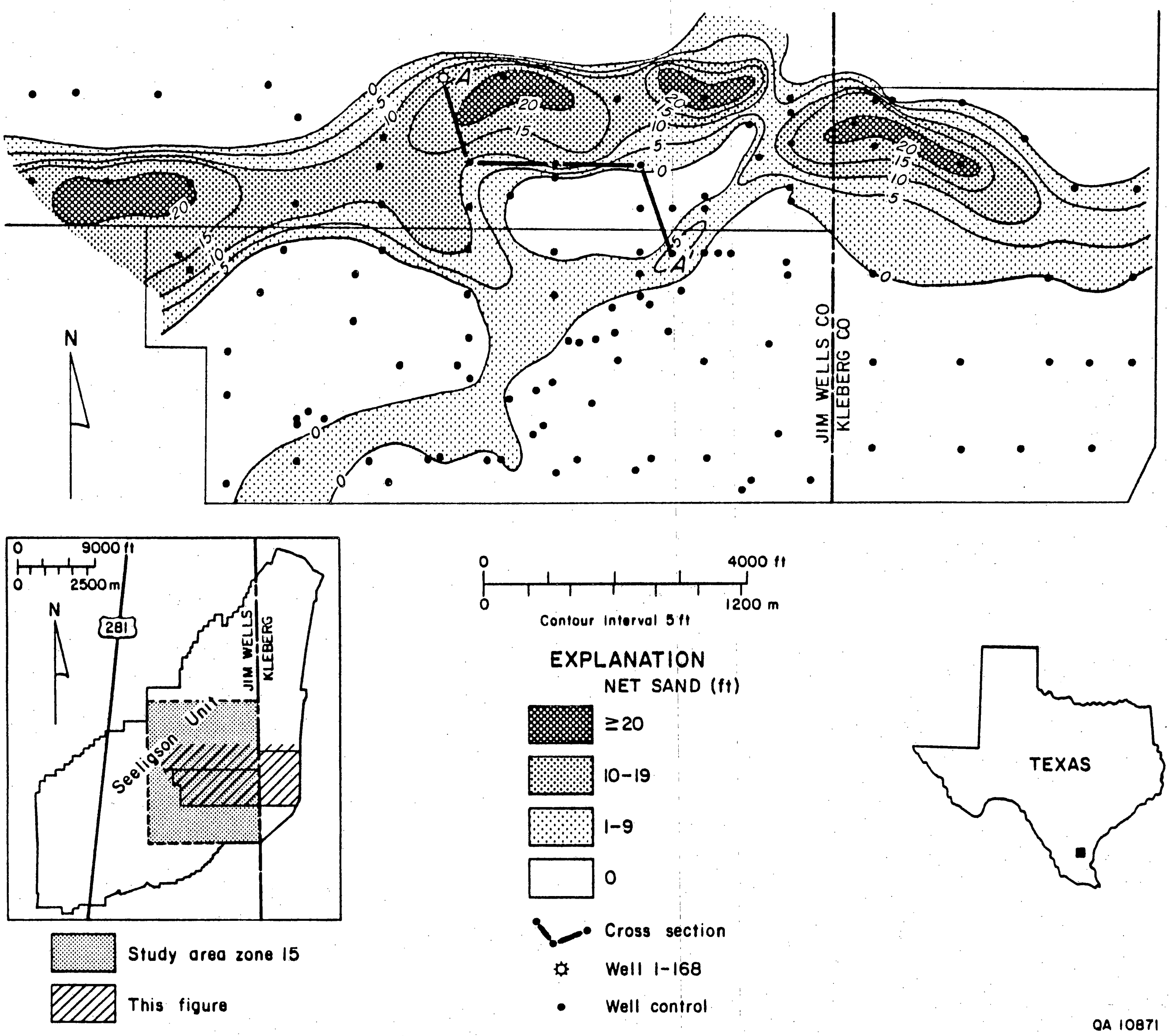

Figure 46. Net-sandstone isopach of Zone 18-C lower.

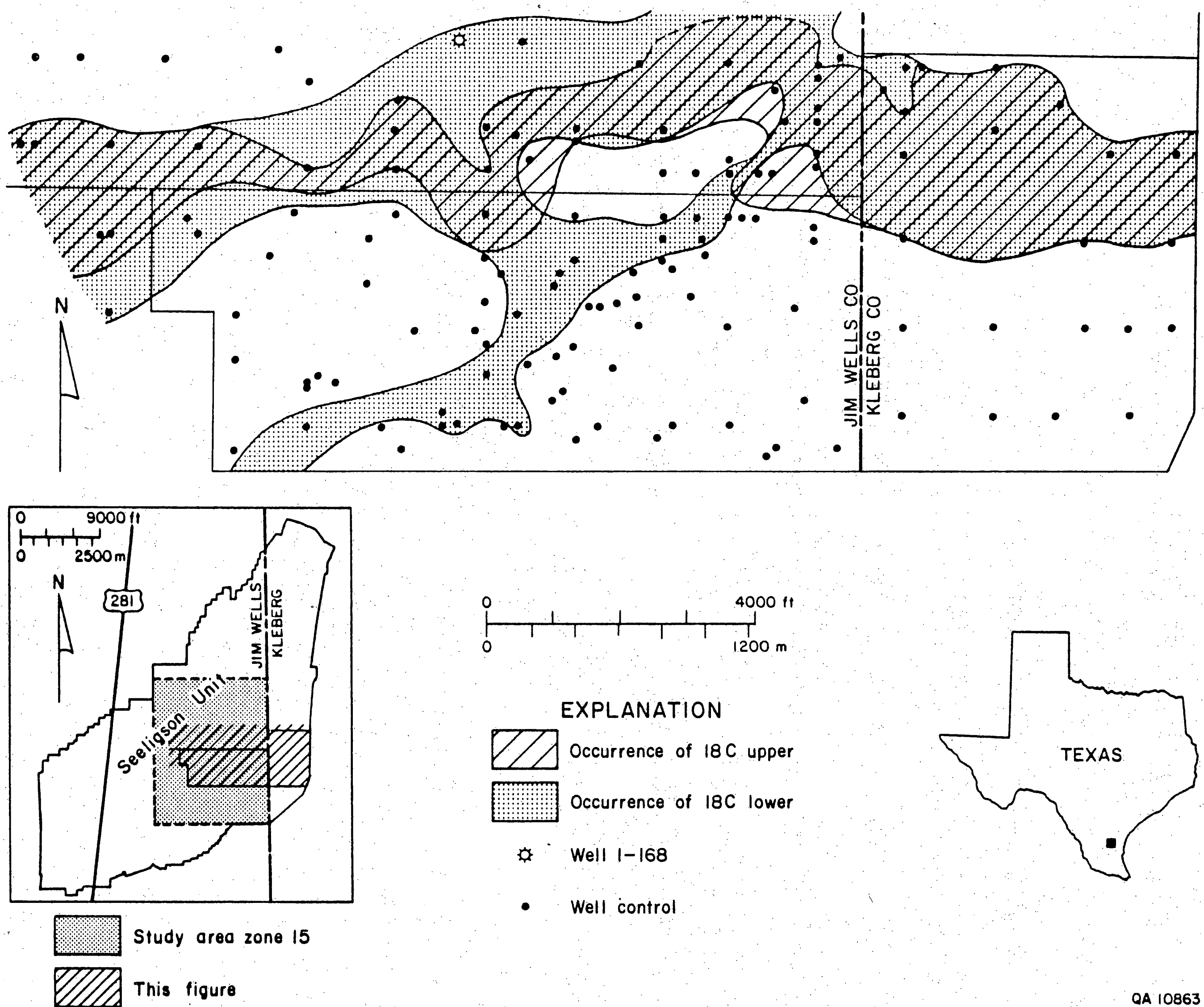

Figure 47. Relationship of Zone 18-C upper and lower channels. Important feature is the absence of production from the 18-C upper channel.

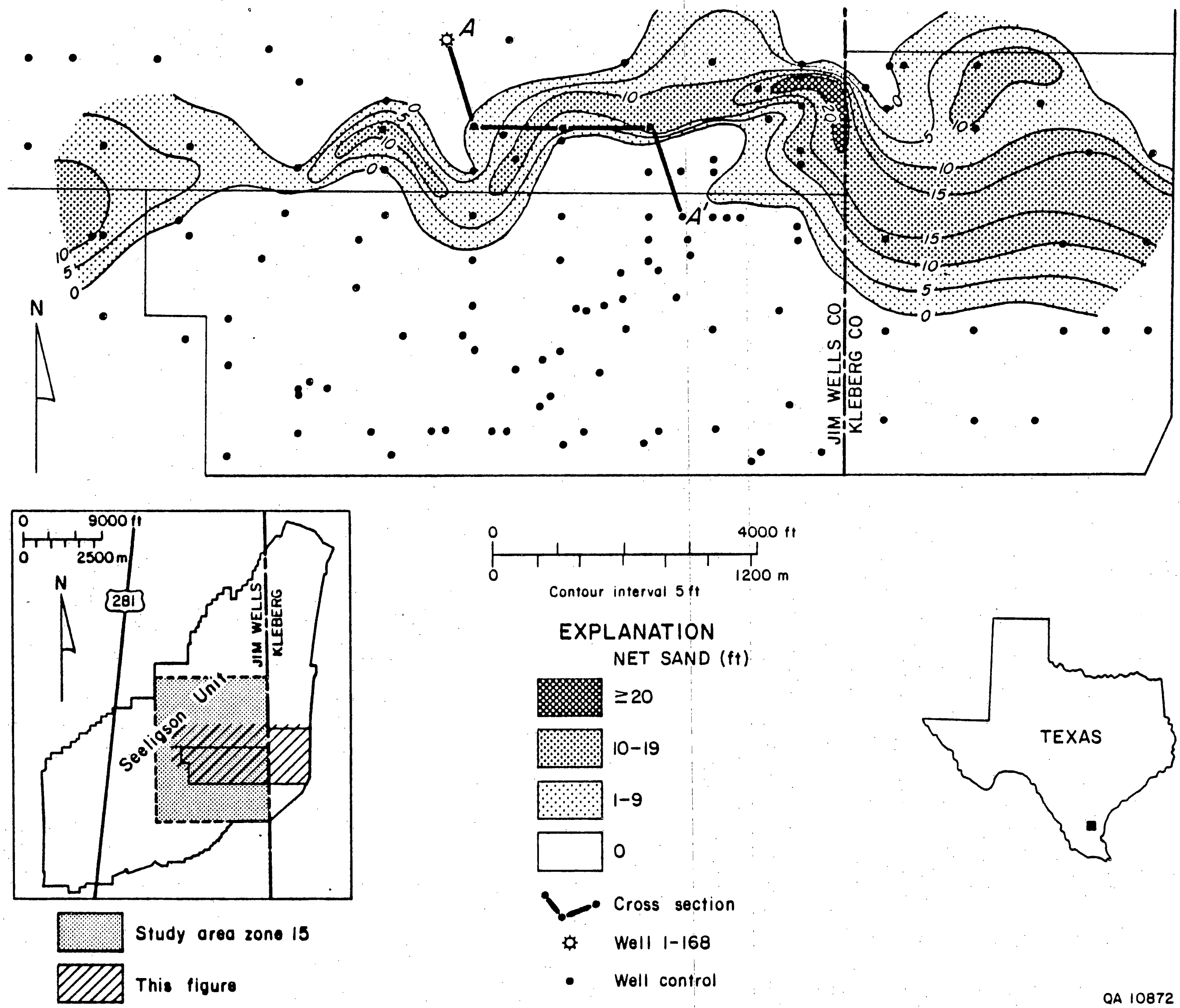

Figure 48. Net-sandstone isopach of Zone 18-C upper.

RECOMPLETION RECOMMENDATIONS AND RESULTS

Four wells were recommended to Sun Exploration and Production Company for recompletion in Zone 15, three testing the 15-C sandstone and one testing the 15-B sandstone. One well was recommended for recompletion in Zone 18-C, testing the 18-C upper sandstone. A summary of recommendations and results on a well-by-well basis follows.

Well 17-17

Zone 15-C sandstone occurs at an electric log depth of 5,390-5,400 ft. In well 17-17, the C sandstone is separated from 15-B by 4 ft of shale (fig. 49). Facies mapping identifies the 15-C as a reservoir-quality channel-fill deposit (fig. 43). There are no current completions in this channel, and the closest production from 15-C, well 16-124A, should be isolated horizontally by muddy floodplain facies (fig. 43). The structural position of well 17-17 is located on the flank of a local structural high (fig. 50).

Digital cased-hole sonic and TDT logs were run in well 17-21, approximately 1,000 ft west of well 17-17 (figs. 42, 43, 49). Preliminary evaluation of the logs indicated gas in the 15-B sandstone, and the equivalent gas effect could be assumed for the underlying 15-C sandstone (W. Howard, personal communication, 1988). Log correlations between wells 17-21 and 17-17 are very good.

Most production in the study area is from Zone 15-B sandstones. The nearest well that perforated the 15-C sandstone is well 16-124A, approximately 4,500 ft to the southwest, where 15-B and 15-C coalesce into an amalgamated unit and currently are producing 1,400 Mcf/d.

This recompletion candidate was selected on the basis of its geological merit and the strength of preliminary log analysis in an adjacent well. The 15-C sandstone was identified as an isolated channel fill situated near the crest of a local structural high, separated vertically from the productive, overlying 15-B sandstone and horizontally from the nearest 15-C perforations by muddy

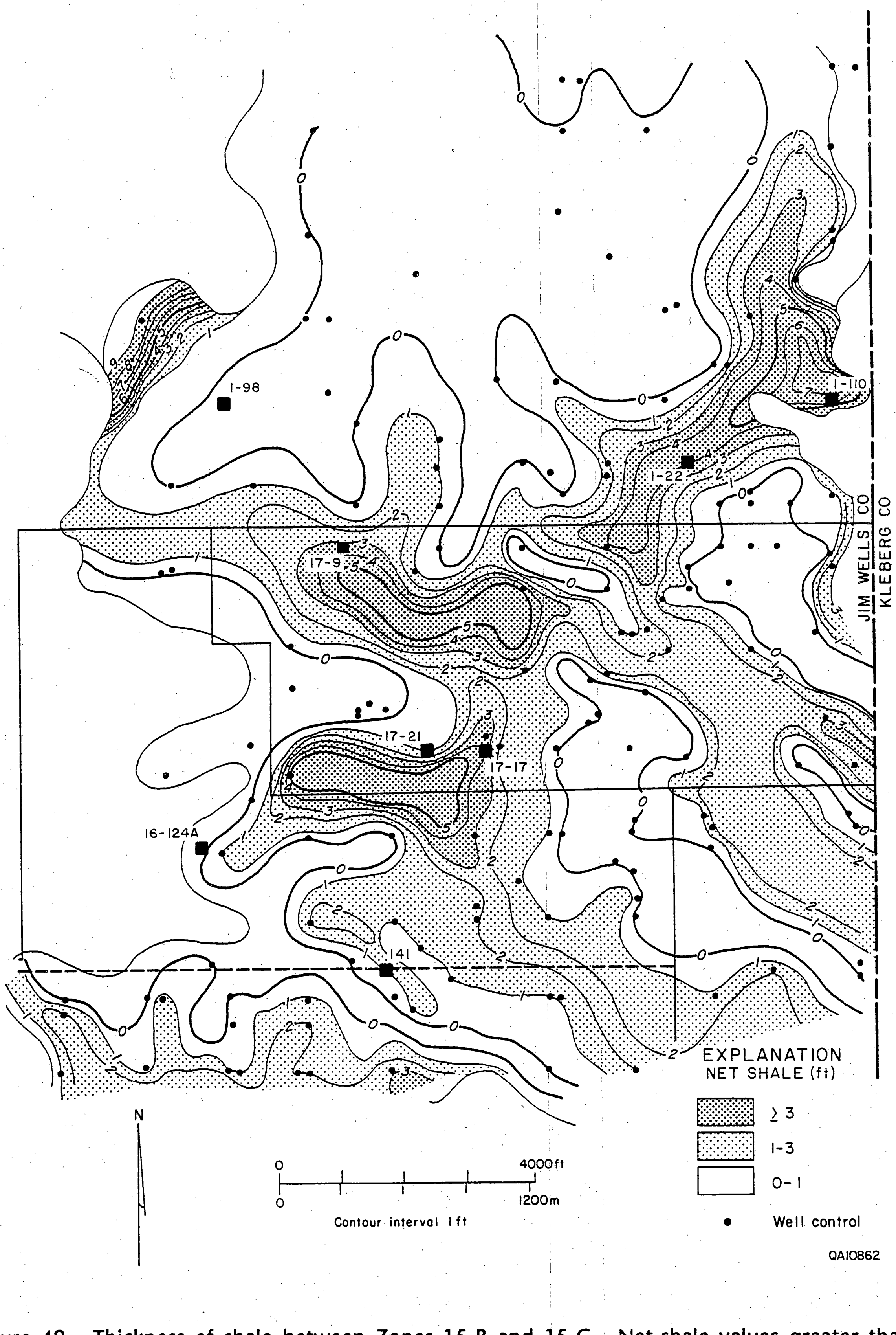

Figure 49. Thickness of shale between Zones 15-B and 15-C. Net-shale values greater than 3 ft should provide an adequate permeability barrier between the two sandstones; net-shale values of 1-3 ft might provide a moderate flow barrier.

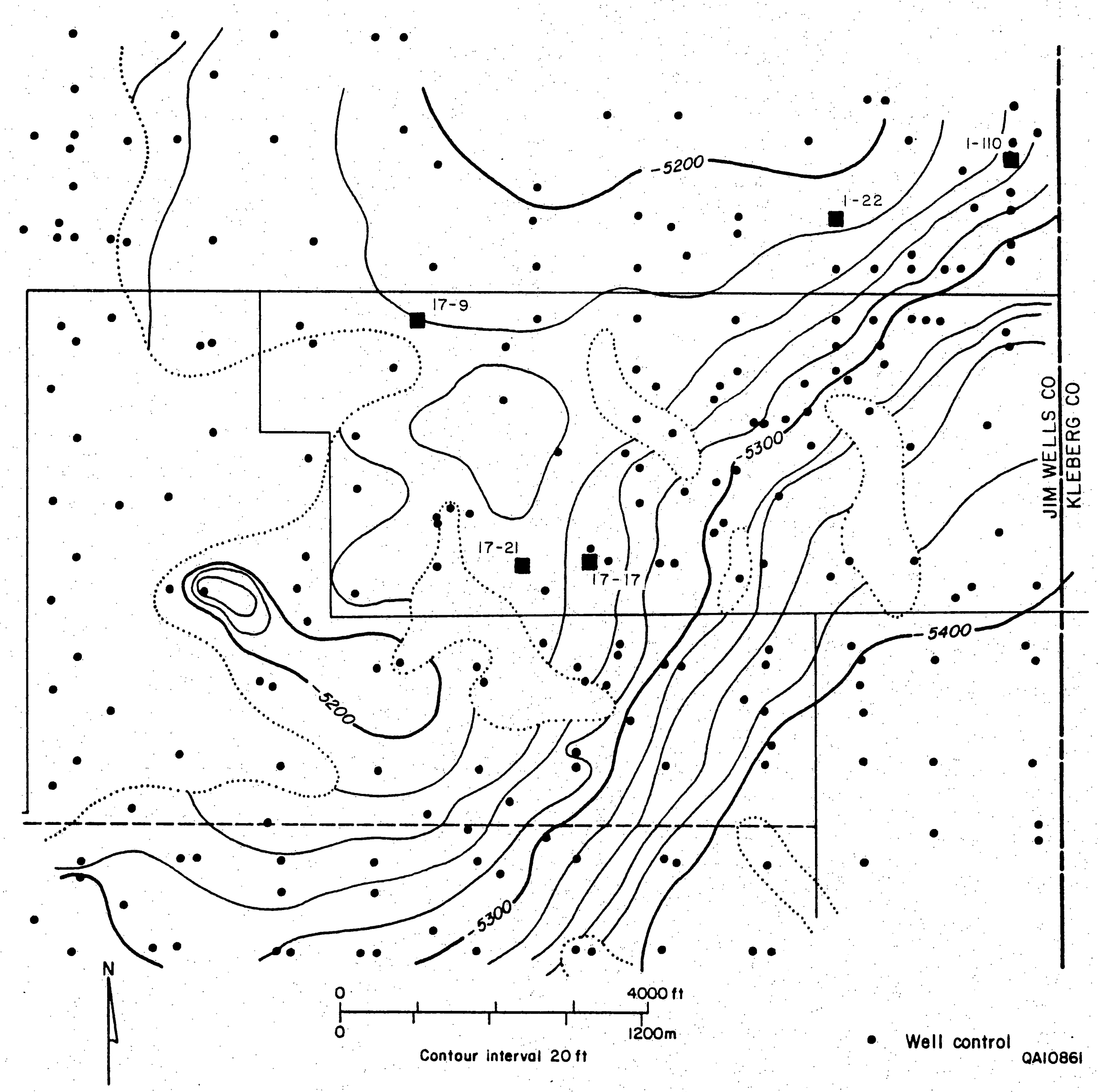

Figure 50. Structure map contoured on the top of Zone 15-C.

floodplain facies (fig. 36). Log analysis in the adjacent 17-21 well was favorable, and the log correlation with well 17-17 is excellent. In addition, Sun Exploration and Production Company had slated the 17-17 well for recompletion in shallower Zone 7-F, requiring only incremental expense to test Zone 15-C. Sun Exploration and Production Company geologists and engineers accepted the concept but uncovered previously overlooked mechanical problems in the hole and were thus unable to agree to a test of this zone in this well. There were no nearby wells available for optional selection.

Well 17-9

Zone 15-C occurs at an electric-log depth of 5,361 to 5,370 ft in well 17-9. Stratigraphically, the setting is similar to that of the 17-17 well, in that the 15-C sandstone is separated from 15-B by 5 ft of shale that should provide an adequate vertical permeability barrier (fig. 49). The 15-C sandstone in well 17-9, however, has been interpreted as a channel-margin deposit that is very close to its westward lateral pinch-out (figs. 42, 43). The nearest completion in 15-C sandstones is approximately 3,000 ft to the northwest in well 1-98 (see figs. 43, 49), where production is from amalgamated 15-B and 15-C sandstones. Several facies changes occur between wells 17-9 and 1-98 (fig. 43) that might provide lateral flow barriers. The structural position of well 17-9 is near the crest of a local high (fig. 50).

A TDT log was run in this well, and interpretations were made by Sun Exploration and Production Company. They concluded that the aggregate interval should contain gas.

As is the case throughout the study area, most Zone 15 production is from 15-B sandstones. Well 1-98 is the closest well to perforate 15-C sands, but the two subunits are coalesced, producing about 220 Mcf/d.

Well 17-9 was selected by Sun for recompletion in Zone 15 primarily on the basis of the results of their log analysis, which favored the upper unit, 15-B. This offered a unique opportunity to recommend testing a concept that might produce two separate results. The geological interpretation of an untapped channel-margin deposit isolated vertically from the overlying productive sandstone and horizontally by facies heterogeneities argued a strong case for probable compartmentalization. Because Sun Exploration and Production Company had already begun work on the recompletion of this well, it was proposed that it test the 15-C sandstone first, by itself. If the reservoir were indeed compartmentalized, relatively high pressure and possible hydrocarbons might be encountered. Unfortunately, the entire zone (both B and C sandstones) was simultaneously perforated before the recommendation was made. The well was tested, acidized, and swabbed from 6/18/88 to 7/1/88. No gas was recovered, although indications of slightly higher than expected pressures were encountered during testing (D. Sadler, personal communication, 1988).

Well 1-110

Zone 15-C occurs at an electric-log depth of 5,390 to 5,402 ft in well 1-110. This well is located in an area where the highly productive 15-B sandstone pinches out (fig. 14), and there are no nearby wells completed in the 15-C sandstone. Facies maps identify the 15-C in well 1-110 as a channel-fill sandstone trending north to south (fig. 43). The well is located on the flank of the primary structural high in the area (fig. 50). A TDT log was run in the well and evaluated by Sun; the company's interpretations indicate that gas should be present in this sandstone.

There is no production from the 15-C sandstone in this channel or in the area. The closest well to perforate this interval is more than 1 mi away, in a well where the 15-B and 15-C sandstones coalesce to form a composite sandstone.

This recommendation offered an opportunity to test an untapped channel-fill sandstone. The salient characteristic of this selection was the identification of the 15-C as the sole sandstone in the interval because of the pinch-out of the overlying 15-B. The sandstone had previously been assumed to be the 15-B, which is highly developed in and around the area, and would likely preclude recompletion. After our presenting the results of the detailed geological evaluation to Sun and emphasizing the stratigraphic interpretations as well as the potential for reservoir compartmentalization in an untapped channel, Sun agreed with the conceptual framework but ultimately rejected the recommendation in this well because of its structural position. However, Sun did agree to recomplete a well updip of 1-110 on the basis of the geologic analysis as part of another package presentation.

Well 1-22

Zone 15-B is located at an electric-log depth of 5,335 to 5,347 ft. Log-facies mapping illustrates a series of coalescing channels flanked by numerous crevasse splays; sandstone 15-B in well 1-22 (see fig. 50) is interpreted as a splay deposit (fig. 41). The well is located on the rim of the primary structural high in the area. Digital cased-hole sonic and TDT logs were run in the well; log analyses indicate a gas-productive zone (Howard and Bolin, 1988).

Most of the gas produced from Zone 15 within the study area is from the 15-B sandstone, and several wells within less than a mile radius have perforated 15-B sands. Because many wells simultaneously produce from both 15-B and 15-C reservoirs, cumulative production figures cannot be disaggregated to the subunit level. However, cumulative gas production for Zone 15 reservoirs within the study area is about 57 Bcf.

This recommendation would test the horizontal isolation of an untapped splay sandstone. The crevasse splay is attached to a channel-fill sandstone that has also not been drilled; however, significant production from 15-B has come from adjacent and merging channels. Sun Exploration and Production Company agreed with this recommendation, although at this time no activity has begun toward testing this reservoir.

A similar geologic setting in La Gloria field, located about 6 mi southwest of Seeligson field, was the site of a successful infill well (W. A. Ambrose, personal communication, 1988). Mobil Oil drilled the La Gloria Gas Unit (LGGU) No. 110, completed in the Jim Wells reservoir. Jackson and others (in preparation) mapped the Jim Wells reservoir and interpreted a crevasse splay environment at the LGGU No. 110. The reservoir had been extensively produced from adjacent channels and other facies, depleting reservoir pressures to the 200- to 300-psi range. Initial pressure in the Jim Wells for the LGGU No. 110 was about 1,300 psi, and the well has produced more than 50 MMcf of gas, documenting a facies-controlled, poorly drained reservoir compartment.

Well 1-22

Zone 18-C occurs from 5,731 to 5,752 ft in well 1-22. The target sandstone is the 18-C upper, which has been identified as a separate genetic sandstone body and interpreted as a reservoir quality channel-fill (fig. 44) deposit horizontally and (to a lesser degree) vertically isolated from the productive 18-C lower. This lateral relationship is best seen on cross section A-A' (fig. 45). Structural position of the well is on the flank of a local high. Digital cased-hole sonic and TDT logs were run in well 1-22. Log analysis indicated that an apparent gas-productive zone would be found in Zone 18-C, although it should be considered a low-resistivity pay.

Gas production from Zone 18-C within the study area is restricted to well 1-168, which has produced 663 MMcf of gas (cumulative). Detailed stratigraphic analysis identifies this productive sandstone as the 18-C lower (fig. 44); no perforations have been made through the 18-C upper unit.

It was recommended that Sun Exploration and Production Company recomplete well 1-22 in the 18-C, upper sandstone, on the basis of the documented geologic evaluation and the favorable log analysis. This recompletion would test an untapped channel sandstone that had previously been treated as the equivalent to the producing subjacent sand (18-C lower) and would not have been considered for additional testing because of its proximity to the sole producing well in the area. Sun agreed to recomplete the well and perforated, acidized, and swabbed from 6/25/88 through 7/6/88 before the well died. No recovery of gas was made, although early shut-in tubing pressures indicated relatively strong pressures had been encountered (D. Sadler, personal communication, 1988). Final BHP's will be taken when the well stabilizes. It is possible that this zone might have been productive if it had been tested for a longer period of time. Duggan and Langston (1988) indicate that a considerable amount of gas reserves may be recoverable from depleted reservoirs, as long as completion and stimulation procedures are followed patiently. They cite examples where more than 30 d of stimulation was required before the well became successful.

CONCLUSIONS

Advanced geological characterization methods can be applied during a search for compartmentalized reservoirs or bypassed gas zones in established fields. Integrating these methods with engineering and petrophysical assessments results in the prediction of isolated hydrocarbon-bearing zones, which can then be tested through well recompletions or infill-well drilling. In Seeligson field, as in many other fields where multiple, vertically stacked, predominantly fluvial reservoirs comprise the stratigraphic framework, abundant opportunities are present for evaluating potentially undrained reservoir compartments.

This study focused on only two of more than 30 reservoirs within a small segment of Seeligson field. Zone 15, which has been developed under the assumption that it is a homogeneous and continuous reservoir, is in fact composed of several separate heterogeneous sandstones. Zone 18-C, also developed under the assumption that it is a homogeneous, continuous reservoir, was found to be composed of two separate sandstones, one of which had never been tested. Five recompletion recommendations were made for wells in both zones. Unfortunately, two were rejected because of mechanical and/or operational problems, two remain untested, and one (Zone 18-C upper) was briefly tested and considered unsuccessful.

Detailed geologic evaluation did, however, explain anomalous BHP's documented between wells completed in Zone 15. Relatively high pressures in four recent recompletions are fundamentally controlled by facies heterogeneities. Two channel complexes are separated by a muddy floodplain facies. One is heavily developed with depleted reservoir pressures, but the other was untapped, and anomalously high pressures were encountered upon recompletion.

LOWER MIOCENE SANDS IN THE TOM O'CONNOR FIELD AREA, REFUGIO COUNTY, TEXAS

by
Dennis R. Kerr

INTRODUCTION

Tom O'Connor field, located in Refugio County Texas, is a northeast-to-southwest trending anticlinal trap containing multiple producing intervals. Structural rollover is related to growth-fault activity along the Vicksburg Fault Zone. Both Oligocene Frio and Miocene sandstones produce gas at Tom O'Connor as well as in adjacent fields (fig. 51). Tom O'Connor field has produced approximately 1 Tcf of gas since its discovery in the 1930's. Miocene sandstone reservoirs are included in the "Atlas of Major Texas Gas Reservoirs" (Kosters and others, in press) as part of the "Moulton/Pointblank streamplain along reactivated Frio Faults" play. Many of the reservoirs in this play are in advanced stages of depletion; however, new pools continue to be discovered. Within Tom O'Connor field, the 4,150- and 4,200-ft sandstones are examples of new pool discoveries, and as of 1985, had produced 400 MMcf of gas.

Lower Miocene sandstones were deposited during the initial offlap of the early Miocene progradational episode (Galloway and others, 1986). Before offlap, Anahuac shelf mudstones of the late Oligocene to early Miocene were deposited during a Gulf-wide transgressional episode. Subsequent to offlap, Marginulina ascensionensis shelf mudstones were deposited during a second, shorter transgressional episode. Early Miocene progradation deposited more than 2,000 ft of fluvial and nearshore sands and muds and shelf sands and muds near the present shoreline at the transition between the North Padre delta depositional system and the Matagorda barrier-strandplain depositional system (Galloway and others, 1986).

This study focused on the nature of initial progradation and geometry of sandstone bodies deposited during progradation. A sequence stratigraphic framework was developed over a regional network of cross sections that extended into adjacent counties and joined with the wider network

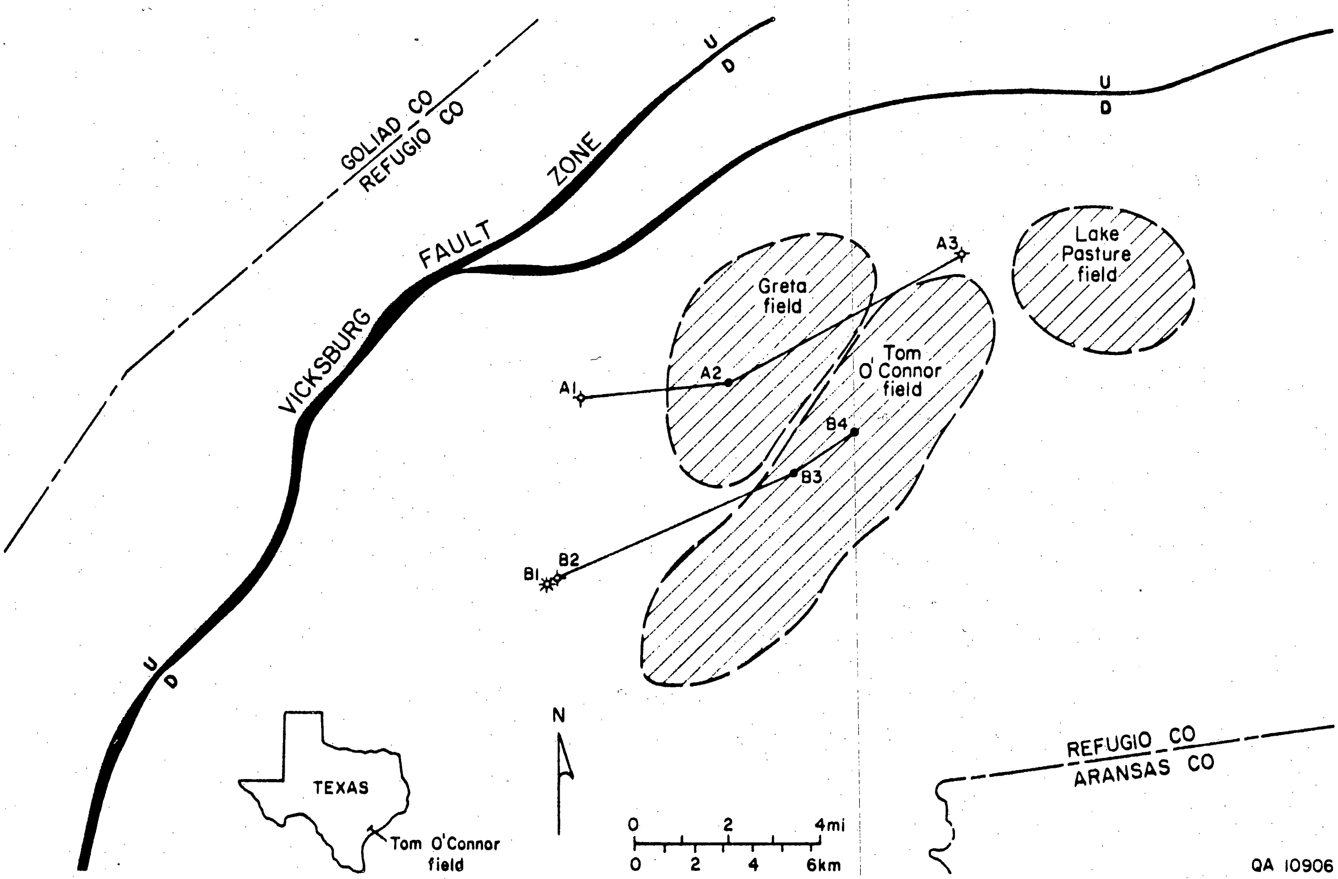

Figure 51. Index map. Location of Tom O'Connor field is shown along with that of adjacent fields with production from Miocene sandstones. Growth faults in the Vicksburg Fault Zone were apparently active during deposition of lower Miocene sediment. Cross sections A and B are illustrated in figure 52.

of Dodge and Posey (1981) and Morton and others (1985b). Within this stratigraphic framework, log-facies and isopach maps were used to refine the distribution of environmental elements within the broader depositional systems outlined by Galloway and others (1986). This report discusses the stratigraphic framework and log facies of the interval that includes the 4,150- and 4,200-ft sandstones.

STRATIGRAPHIC FRAMEWORK AND LOG FACIES

The Anahuac Shale and Oakville sandstones are constructed of parasequences—transgressive-regressive facies successions that are separated by marked marine flooding surfaces (Van Waggoner and others, 1987). These surfaces are disconformities that are lower in rank than the unconformity surfaces separating stratigraphic sequences. Parasequences are the "building blocks" of stratigraphic sequences. This study examined mostly the parasequence development that followed maximum flooding (approximated by the Heterostegina-Marginulina zone) through progradation of early Miocene sands.

Wire-line log identification of parasequences is based on two criteria: (1) Each parasequence should coarsen upward; even in muddy intervals this trend is noted on the amplified short-normal resistivity profile (fig. 52, parasequence 7). The parasequence boundary is commonly marked by a thin low resistivity interval or low resistivity marker (P. Vail, personal communication, 1988). (2) Parasequences are correlative over a wide region (hundreds to thousands of square miles). Parasequences can contain one or more transgressive-regressive facies patterns representing relatively local coastal retrogradation and progradation, but it is the regionally continuous transgressive intervals that distinguish one from the other.

In the lower Miocene, parasequences in the Anahuac Shale (subsequent to maximum flooding) are about 40 to 50 ft thick. In the overlying basal Oakville the parasequences progressively thicken to 100 to 200 ft. Local variations in thickness occur in the vicinity of growth faults and their attendant structures and where erosion along the parasequence disconformities has removed part of

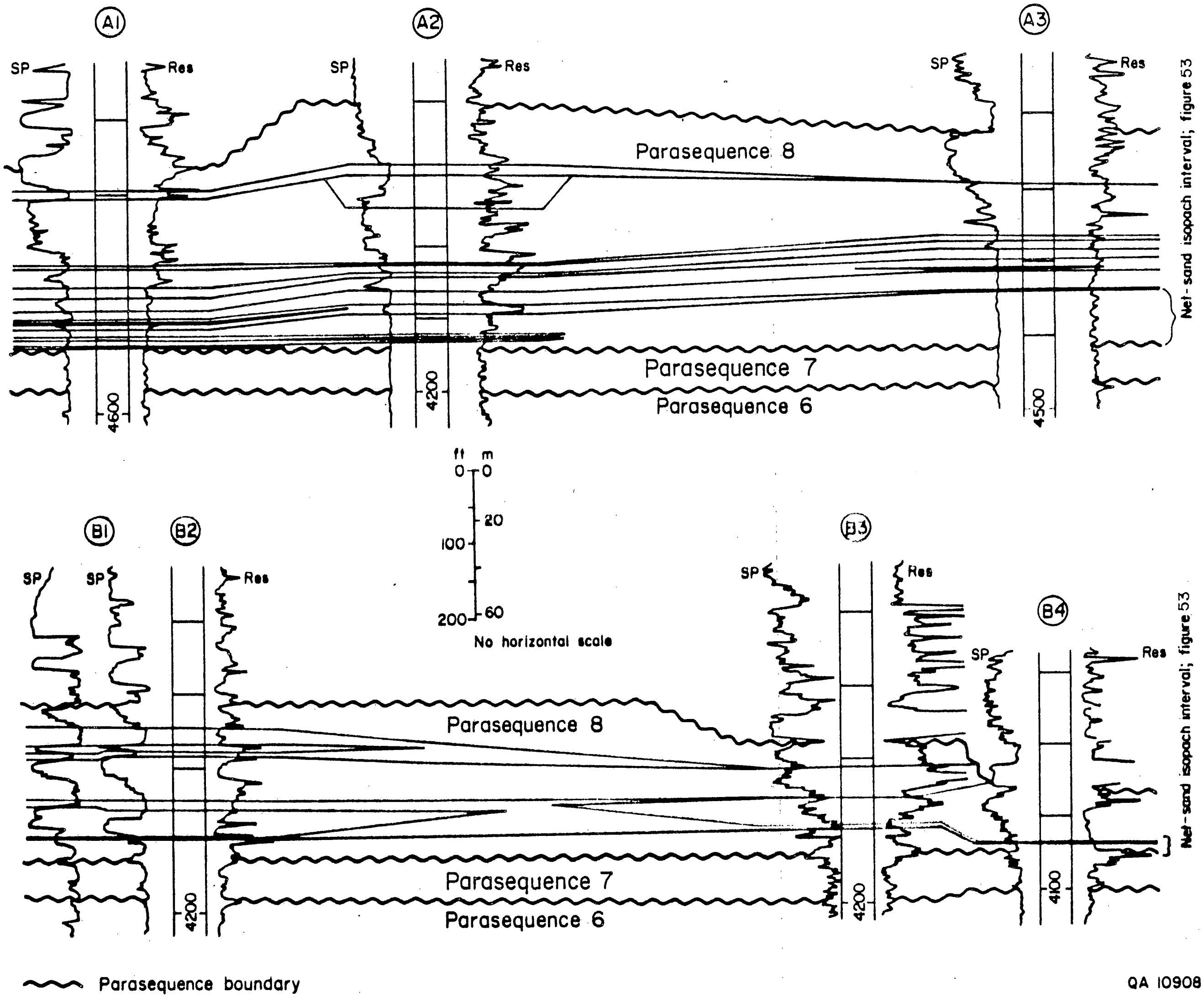

Figure 52. Cross sections A and B. Serrated lines separate parasequences that are based on a regional wire-line log cross-section network. See figure 51 for location of wells and table 4 for well identification.

Table 4. List of well names for wire-line logs used in figure 52.

Figure Reference	Operator	Well Name	Tobin Grid
A 1	Tennessee Gas Transmission Co.	Hynes F-25	13S-23E-9
A 2	Atlantic Refining Co.	Tom O'Connor 8	13S-23E-8
A 3	Southern Petroleum Exploration, Inc.	Hynes 1	13S-24E-4
B1	Seaboard Oil Co. and R. W. Young	Hynes A4	14S-23E-4
B2	B. Graham	Fox 1	14S-23E-4
B3	Quintana	Tom O'Connor C67	14S-23E-2
B4	Quintana	Tom O'Connor C75	14S-23E-1

the previously deposited parasequence (for example, base of parasequence 9 in well A1, fig. 52). Parasequence 8, which includes the 4,150- and 4,200-ft sandstones in its lower part, is 150 to 300 ft thick in the hanging-wall block near the Vicksburg Fault Zone and thins to 100 ft about 10 mi away (southeast), then gradually thins to 50 ft over another 20 mi. The abrupt thinning near the Vicksburg Fault Zone is approximately coincident with growth-fault-related anticlinal structures such as the Tom O'Connor anticline.

Wire-line log character and sand-body geometry are used to delimit three facies elements. Facies 1 has a funnel-shaped log character (for example, 4,125 to 4,240 ft in well A3, fig. 52) representing progradational, sand-rich coastal settings. Facies 1 is further divided on the basis of geometry into Facies 1a, having a broad, lenticular geometry and Facies 1b, having a depositional-strike-parallel, lenticular geometry. Facies 1a is regarded as the outbuilding of channel-mouth bars, the deposits of which are typically stacked into 20- to 30-ft-thick units (fig. 52). Facies 1b is regarded as the deposits of the barrier-strandplain core that typically occur as single sand bodies within a parasequence.

Facies 2 has a bell-shaped log profile and a narrow, lenticular geometry (for example, 3,900 to 3,950 ft in well A2, fig. 52); it is interpreted as a channel-fill depositional setting. Channel-fill deposits are generally thicker where they were deposited immediately above a parasequence boundary (as compared with channel-fill-deposit thickness within the upper parts of a parasequence [>50 ft]). Facies 1 and 2 are the principal sandstone intervals of the lower Miocene in the Tom O'Connor area. They develop into 50- to 100-ft-thick complexes in the upper intervals of a parasequence. Facies 1 grades shelfward and downward into Facies 3.

Facies 3 has a serrate to suppressed, straight log character and a gentle, Gulf-ward thickening wedge geometry. Facies 3 is interpreted to represent lower shoreface to offshore environments. The serrate log profile reflects the interstratified mudstone and sandstone composition of Facies 3. The 4,150- and 4,200-ft sandstones of Tom O'Connor field are examples of sandstones included in Facies 3. These 2- to 10-ft-thick sands reside in two positions within a parasequence. First, they rest at the base where they probably represent reworking of former Facies 1 or 2 sands during transgression (for example, 4,120 ft in well B2 and 4,130 ft in well B3, fig. 52). Second, they reside between the parasequence base and the progradational Facies 1 and 2 complexes (for example, 4,080 ft in well A2, fig. 52). In the latter case, Facies 3 sandstones either are isolated in mudstones, or they laterally contact the thick progradational Facies 1 and 2 complexes.

Figure 53 illustrates the net-sandstone distribution of the lower parasequence 8, the interval encompassing the 4,150- and 4,200-ft sandstones (fig. 52). Net-sand thickness increases to a maximum observed thickness of 25 ft toward the Vicksburg Fault Zone, following parasequence gross thickness described above. The isopach interval is composed of several 2- to 5-ft-thick sandstones that tend to increase in number toward the fault zone (compare interval in B versus A of fig. 52). The net-sandstone zero isopach traverses the crest of the Tom O'Connor anticline, and net-sandstone isopachs appear to deflect around the Greta anticline as well. The net-sand-isopach map pattern suggests that a positive bathymetric feature may have limited offshore sand sedimentation (Facies 3) during the initial, transgressive phase of parasequence 8.

CONCLUSIONS

Parasequence 8, which contains the Tom O'Connor field new gas pool 4,200- and 4,150-ft sandstones, developed during growth-fault activity along the Vicksburg Fault Zone. Near the fault zone, gross interval markedly thickens to 300 ft. About 6 mi gulfward, or along the southeast flank of Tom O'Connor field, the parasequence thins to less than 100 ft, and farther gulfward, the parasequence reaches 100 ft before gradually thinning to about 50 ft out to the southeastern limit of the area mapped (approximately 20 mi from the fault zone). Thus, a complementary anticlinal structure appears to have developed gulfward of the Vicksburg Fault Zone during deposition of this particular parasequence. Moreover, this growth-fault activity may have influenced local bathymetry.

Log-facies and net-sandstone-isopach maps also reflect growth-fault activity. Deposition of the 4,150- and 4,200-ft sandstones, as part of the offshore system during initial parasequence deposition, was confined between the Vicksburg Fault Zone and the contemporaneous anticlinal

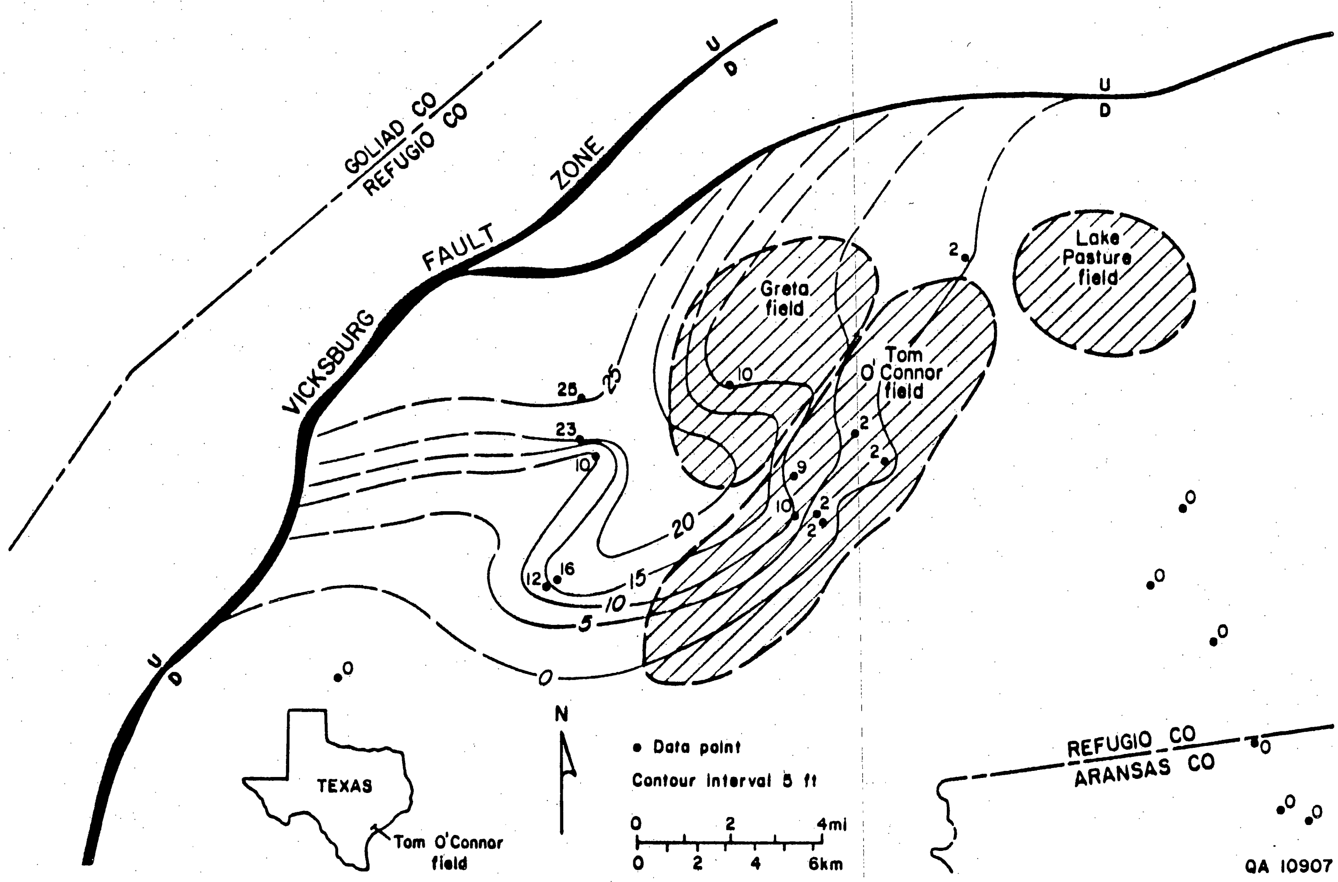

Figure 53. Net-sandstone-isopach map. Net-sandstone thickness of the lower part of parasequence 8 (fig. 52) is mapped in 5-ft contour intervals. Note net-sandstone thickness increases toward Vicksburg Fault Zone and terminates along crest of Tom O'Connor field anticline.

crest. Maximum net-sandstone thickness is 25 ft, and the sandstone edge (zero net-sandstone isopach) is limited by the anticlinal flank through Tom O'Connor field. Progradation of the fluvial and barrier-strandplain (or delta) systems surmounted the anticlinal crest and proceeded gulfward.

To what extent growth faulting and its complementary structural elements affect the distribution of offshore sands (for example, 4,150- and 4,200-ft sandstones) remains to be examined elsewhere. The relationship between growth faulting, bathymetry, and offshore sand sedimentation may prove to be a means of producing reservoir compartments in relatively thin, gas-prone offshore sandstones.

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