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SECONDARY NATURAL GAS RECOVERY: TARGETED TECHNOLOGY APPLICATIONS FOR INFIELD RESERVE GROWTH: CASE STUDIES EVALUATING THE BENEFITS OF SECONDARY GAS RECOVERY, ONSHORE GULF COAST, SOUTH TEXAS

TOPICAL REPORT

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16. Abstract (Limit: 200 words)

Economic recovery of natural gas in reservoirs with near-tight to conventional porosity and permeability can be improved through geologically based infill-development strategies. Old gas fields may contain new infield reservoirs, incompletely drained reservoir compartments, untapped reservoir compartments, and bypassed reservoirs. These secondary resources may be identified by a combination of log evaluation and production and pressure analyses, and they are controlled by structural and stratigraphic heterogeneity. Many gas fields in the Gulf Coast may contain opportunities for identifying additional gas resources at modest costs. Remaining natural gas in these fields can be contacted either by recompleting existing wells that have bypassed reservoir compartments or by drilling strategically targeted infield wells. Exploration for new, untapped, or incompletely drained reservoir compartments or bypassed gas zones in old fields can be improved by using state-of-the-art formation evaluation tools and engineering, production, petrophysical, and geological analyses. The economics of developing and producing the secondary gas recovery (SGR) resource is evaluated for two producing properties in existing fields. The case I study area (North McFaddin field) had total operational and development costs (excluding royalties) of $0.58 per mcf, compared to total costs in case II (Agua Dulce field) of $0.83 per mcf. Future application of SGR concepts and technology to strategically targeted well locations and recompletions could further lower development costs.

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Case studies, integrated geologic, engineering, and petrophysical evaluation of reservoirs, identification of secondary natural gas resources

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RESEARCH SUMMARY

Title	Secondary Natural Gas Recovery: Targeted Technology Applications for Infield Reserve Growth: Summary of Two Case Studies in Evaluating the Benefits of Secondary Gas Recovery, Onshore Gulf Coast, South Texas
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5082-211-1718, titled "Secondary Natural Gas Recovery: Targeted Technology Applications for Infield Reserve Growth"
Principal Investigators	Robert J. Finley and Raymond A. Levey
Report Period	January 1992–December 1992
Objectives	The objective of this report is to assist natural gas producers in evaluating the feasibility of developing additional natural gas resources in existing fields with conventional permeability and porosity. Both structural compartmentalization and stratigraphic variability in lower Miocene and middle-Oligocene reservoirs are described and evaluated from 2 mature gas fields located in 2 of the 10 onshore Frio Formation gas plays and 1 of the 5 Miocene gas plays in Texas. This report documents the technical and cost-benefit analyses of infield development and serves as a model for evaluating potential incremental resource development in similar gas fields in the United States.
Technical Perspective	A major goal of the Infield Natural Gas Reserve Growth Joint Venture project is to assess the potential for maximizing economic recovery of natural gas, mainly in reservoirs with low to conventional porosity and permeability. These reservoirs may contain new infield reservoirs, incompletely drained compartments, untapped reservoir compartments, and bypassed reservoirs. These secondary resources may be identified by a combination of log evaluation, production and pressure analyses, and depositional control on reservoir distribution augmented by structural segmentation. Many conventional permeability gas fields in the Gulf Coast are thought to contain similar opportunities for identifying additional gas resources at modest costs. Remaining natural gas in these fields can be contacted either by recompleting existing wells that have bypassed reservoir compartments or by drilling additional infield wells. Exploration for new, untapped, or incompletely drained reservoir compartments or bypassed gas zones in old fields can be improved by using state-of-the-art formation evaluation tools and interpretation techniques with detailed geologic and production studies that integrate engineering, petrophysical, and geological analyses.
Results	This report summarizes the results of applying concepts and techniques developed as part of the infield reserve growth joint venture to recover additional gas from mature fields. Two case studies were evaluated for secondary gas resources. In case I, secondary gas resources totaling 19 Bcf were identified in bypassed reservoirs deposited in thin-bed barrier/strandplain deposits. In case II, secondary resources of 7 Bcf were defined in fluvial depositional reservoir facies segmented by structural compartments and affected by stratigraphic variability and diagenesis.

In case I, identification of depletion-drive thin-bed reservoirs using the currently available state-of-the-art induction array tool also identified high-productivity bypassed reservoirs. Detailed stratigraphic analysis of multiple thin-bed intervals, in combination with resistivity cutoffs and spontaneous potential ratios, helped target potential locations for secondary gas resources and enhanced the operator's ability to recover these secondary gas resources.

In case II, both thin-bed and thick reservoir intervals containing secondary gas resources were identified and evaluated using standard well logs, pressure tests, and sidewall core evaluation. Successful recompletion of one zone established production from a thin-sandstone bypassed reservoir with an estimated ultimate recovery of 400 million cubic feet (Mmcf) of gas.

Technical Approach

These case studies integrated geologic subsurface mapping, petrophysical techniques (including high-resolution logging), and engineering analyses (pressure transient buildup tests) to evaluate the costs and benefits of developing incremental gas resources in mature fields.

<u>The technical approach included</u>

(1) Subsurface mapping after (a) performing detailed stratigraphic correlation of productive reservoir horizons, (b) evaluating reservoir thickness in the context of depositional facies, and (c) identifying structural compartments from well log correlations.

(2) Use of high-resolution and spectral gamma-ray well log data to demonstrate the applicability of state-of-the-art logging techniques in identifying infield gas resources.

(3) Bottom-hole pressure testing of reservoir zones in correlative reservoirs to determine the degree of communication.

(4) Analyses of production history and pressure data to compare volumes of original gas in place with estimates of recoverable resources.

<u>The cost-benefit analysis for each case study included</u>

(1) Documenting the commitment of professional effort for geological, petrophysical, and engineering analyses.

(2) Documenting the cost of incremental data, including pressure measurements, logging, and well log data processing.

(3) Reducing development costs by proposing targeted recompletions and infield wells.

(4) Developing rate-time relationships required to schedule recovery of the additional gas resources.

(5) Quantifying the natural gas resources that could be economically recovered by targeted technology applications.

Implications

This report summarizes the results of integrated geological, petrophysical, and engineering analyses through two case studies to document the potential benefits of additional development in existing fields. These fields were believed to be fully developed or exhausted of gas resources. Defining the technical approaches and key concepts for identification of gas resources in these fields indicates that the potential for low-cost reserve growth exists in fields with conventional reservoirs. The two cases presented demonstrate that the methodologies being developed by the Infield Reserve Growth Joint Venture can be successfully applied by small operators in mature gas fields. The Secondary Natural Gas Recovery project is currently transferring technology and reporting results from this research project to the gas industry through publications, short courses, and workshops.

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EXECUTIVE SUMMARY

In a comprehensive study of the potential for natural gas in the United States, the National Petroleum Council (NPC) identified 1,295 Tcf of technically recoverable resources, including proved reserves, conventional resources, and nonconventional resources.* The NPC also identified 216 Tcf of predicted reserve appreciation of nonassociated gas from the lower 48 states on the basis of NPC projections about gas well drilling activity (National Petroleum Council, 1992). The application of Secondary Natural Gas Recovery (SGR) project technologies is directed at recovering the 216 Tcf of natural gas reserve appreciation identified by the NPC.

The research summarized in this report is part of a broad multiyear, multifield research program designed to investigate targeted technology applications for infield reserve growth in the lower 48 states. Previous SGR project studies of Gulf Coast sandstone gas reservoirs focused on applying SGR concepts and technologies in evaluating large properties that produced from both deltaic and fluvially dominated reservoirs. This study demonstrates the applicability of SGR technologies in identifying infield gas reserve growth opportunities on small leases in mature fields operated by independent producers. The SGR project technologies used to identify the infield gas reserve growth opportunities in two case studies are summarized. In addition, an economic evaluation was undertaken to document the economic benefits of the SGR approach to developing gas resources and to demonstrate that small independent operators can economically convert technically recoverable resources into developed reserves.

With the cooperation of independent gas producers, the reserves, economics, and benefits of SGR development are presented for two separate field areas. Both case-study areas are in fields that are more than 50 yr old and have reservoir intervals that were penetrated and produced by older wells before this study. The normal-pressured reservoirs have primarily depletion-drive mechanisms and are at moderate depths of less than 7,000 ft.

* The estimate of 1,295 Tcf of natural gas refers to the technically recoverable resource base as of January 1, 1991, and assumes that current access moratoria expire as scheduled. The estimate also incorporates technology advancement through 2010.

The evaluation of recovering the gas resources indicates that both areas have substantial economically recoverable reserves. In this economic evaluation an effort has been made to account as fully as possible for costs and to take into consideration appropriate elements of risk in terms of the operating environment and resource recovery. The case I study area has a total cost of $0.58 per mcf, excluding royalties. The case II study area has a total cost of $0.83 per mcf, excluding royalties. In both case studies the production and development costs have been calculated on the basis of heavily risk-weighted reserves and are therefore conservative. The corresponding total cost estimates calculated with unrisked reserves for case I and case II would be $0.31 per mcf and $0.49 per mcf, respectively.

The economics of developing and producing the SGR resource are different in each case study area. The primary difference is that the case II study area has smaller reservoir compartments. As a result, development costs are higher because more wells and recompletions are required to access the SGR resource. The smaller reservoir compartment size is caused in part by faulting, depositional, and diagenetic effects on reservoir productivity. Future application of new technologies could lower development costs. The benefits of applying SGR concepts and technology to strategically targeted well locations and recompletions are examined for these two case studies.

OBJECTIVES

Prior to 1970, large quantities of natural gas were produced at low cost from large reservoirs. Since that time, increments of reserve additions have become smaller as gas fields have matured and the use of advanced technology and new geologic models of gas occurrence have been necessary to maintain gas supply. The SGR project is facilitating the continued development of U.S. domestic gas supply by transferring technology to independent operators and demonstrating the application of low-cost strategies to maximize the economic recovery of incremental natural gas from known fields. The objective of this study is to demonstrate the application of SGR concepts and technologies in cooperation with operator-initiated reexploration in two separate mature onshore fields, by using integrated geologic, engineering, and petrophysical analysis and by conducting an economic evaluation of the resource development.

As in previous SGR studies of much larger properties operated by major producers (Finley and others, 1990; Sippel and Levey, 1991; Ambrose and others, 1992; Grigsby and others, 1992; Langford and others, 1992; Levey and others, 1992), this work focuses on conventional porosity and permeability sandstones in the Gulf of Mexico basin. The reservoirs described therein are representative of a much wider spectrum of onshore gas fields along the Texas Gulf Coast. This report documents both technical and cost-benefit analyses of infield development and serves as a model for the evaluation of potential incremental resource development in similar fields in the lower 48 states.

INTRODUCTION

Recent analysis of domestic natural gas resources by the National Petroleum Council (1992) indicates that the lower 48 states have a diverse and vast resource base of 1,295 Tcf of technically recoverable resources, including proved reserves, conventional resources, and nonconventional resources. Of this resource base, 216 Tcf is expected to be recoverable by reserve appreciation of nonassociated gas from the lower 48 states. Full recovery of the 216 Tcf of natural gas will require the integrated application of cost-effective technologies from the disciplines of geology, engineering, geophysics, and petrophysics. The Secondary Natural Gas Recovery (SGR) project aims to develop and disseminate cost-effective technological applications in each of these disciplines in order to maximize the economic recovery of this important infield gas resource.

A recent trend in exploration and development has been the shifting of much of these activities and expenditures by the large integrated companies away from the lower 48 onshore gas resources in favor of perceived greater profitability overseas and in frontier areas. This trend has important implications for our future domestic gas supply. Responsibility for continued development of a large portion of the nation's gas resources will be in the hands of small and mid-sized independents. There are currently more than 1,500 such independent producers actively engaged in Texas Gulf Coast gas field development. This trend presents a valuable opportunity for independents as they seek to recover the substantial remaining gas resources identified in the 1992 resource assessment completed by the National Petroleum Council (1992).

Previous SGR project topical reports have described applications of SGR methodologies by major producers and large independent gas operators in large gas fields. The case studies presented here demonstrate that those methodologies are cost effective and can be successfully applied by small operators, who typically operate in limited geographical areas within both large and small gas fields. These case studies use Oligocene and Miocene reservoirs from gas-productive trends in the onshore Texas Gulf Coast (figs. 1 and 2) to demonstrate the application of the technology, concepts, and economic feasibility of secondary gas recovery. The Oligocene and the Miocene are the most

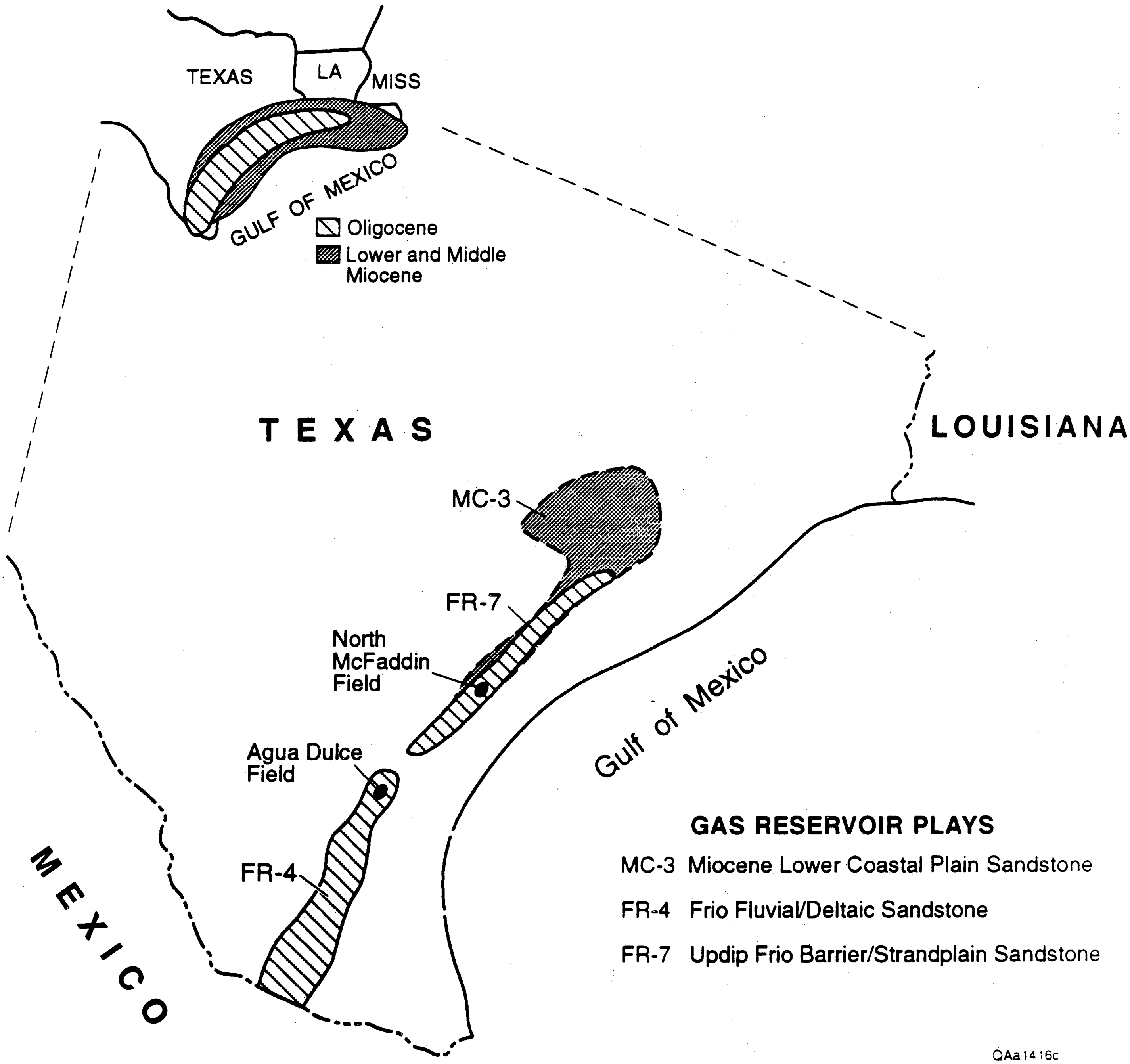


Figure 1. Location of Oligocene and Miocene gas provinces, Texas.

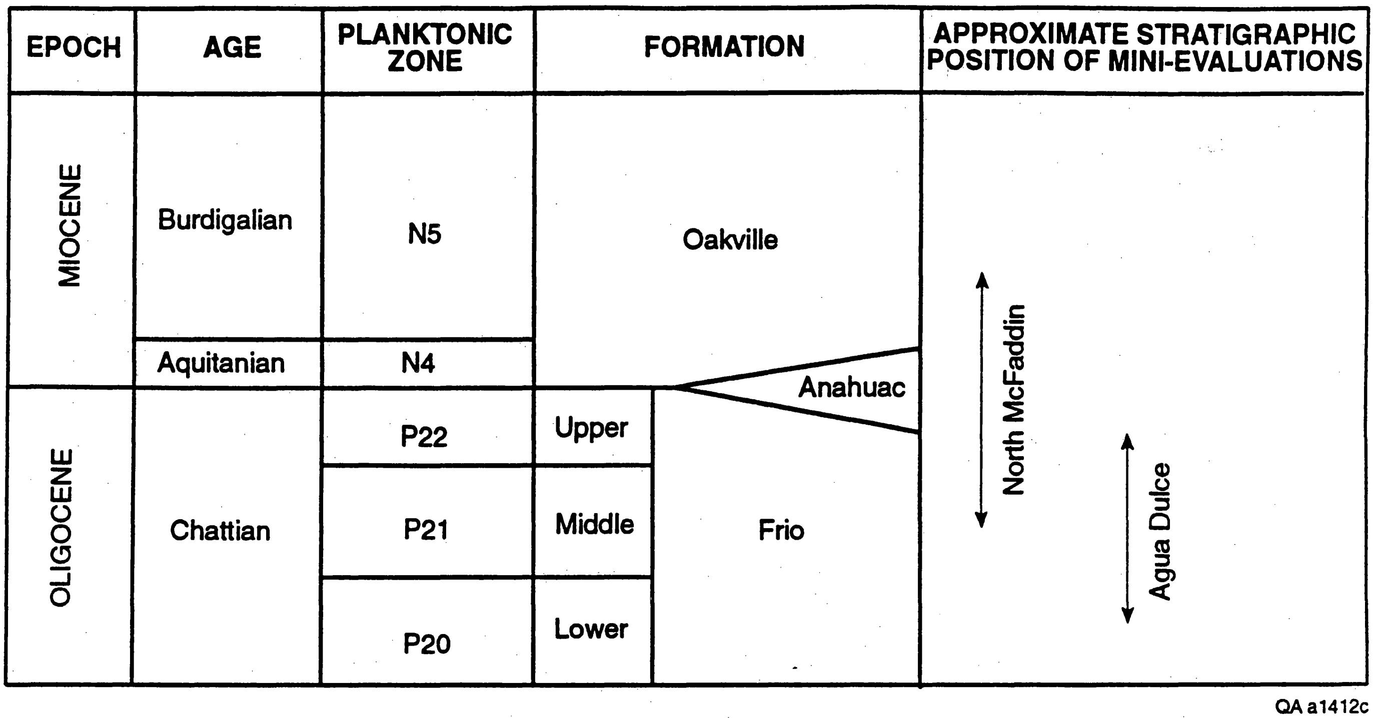


Figure 2. Lithostratigraphic and biostratigraphic framework of the mini-evaluation studies.

important gas-productive intervals in the Gulf of Mexico basin, having produced 118 Tcf and 148 Tcf, respectively. Together these volumes make up 69 percent of the cumulative gas produced in the Gulf of Mexico basin through 1987. This study evaluates the structural (fig. 3) and depositional settings (fig. 4) of reservoirs in three Texas onshore gas plays in fluvial and barrier/strandplain settings in Agua Dulce and in North McFaddin fields. The Agua Dulce property is operated by Pintas Creek Oil Company, and the North McFaddin property is operated by Anaqua Oil and Gas, Inc. Both companies are independent operators headquartered in Corpus Christi, Texas. Despite differences in geological environment and operating styles, significant infield reserve growth potential has been identified and is currently being developed using SGR concepts. Mature fields with existing production infrastructure can be reexplored using SGR concepts and technology to identify and develop low-cost secondary gas reserve additions. Although many Gulf Coast gas operators have focused their exploratory efforts toward the deeper pool targets, secondary gas can be found within bypassed, incompletely drained, and untapped compartments of known reservoirs and new infield reservoirs (fig. 5) in existing fields.

COMPARATIVE ANALYSIS OF CASE STUDIES

Similarities and differences between the two case studies are presented in this section, which provides a brief comparison of their key geologic factors. Geologic factors, operational considerations, and technical approaches are summarized in table 1.

Geologic Factors

Structural Setting, Reservoir Continuity, and Trapping Mechanism

Reservoirs of the case I study area are typically more continuous than those of the case II study area. This continuity is largely a function of postdepositional deformation. Reservoirs of the case II study area possess a greater potential for structural compartmentalization than those of the case I

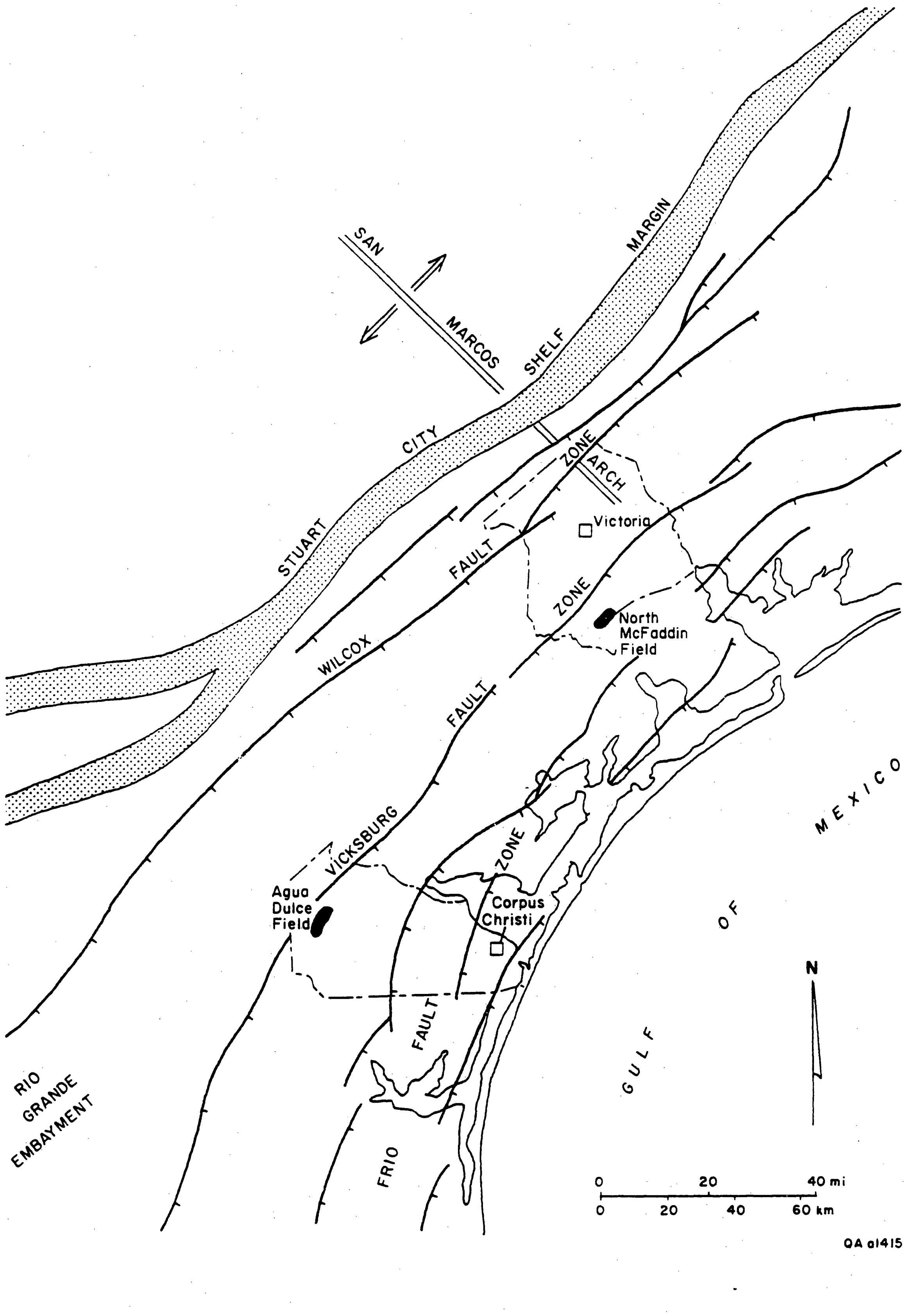


Figure 3. Tectonic framework of the mini-evaluation study areas.

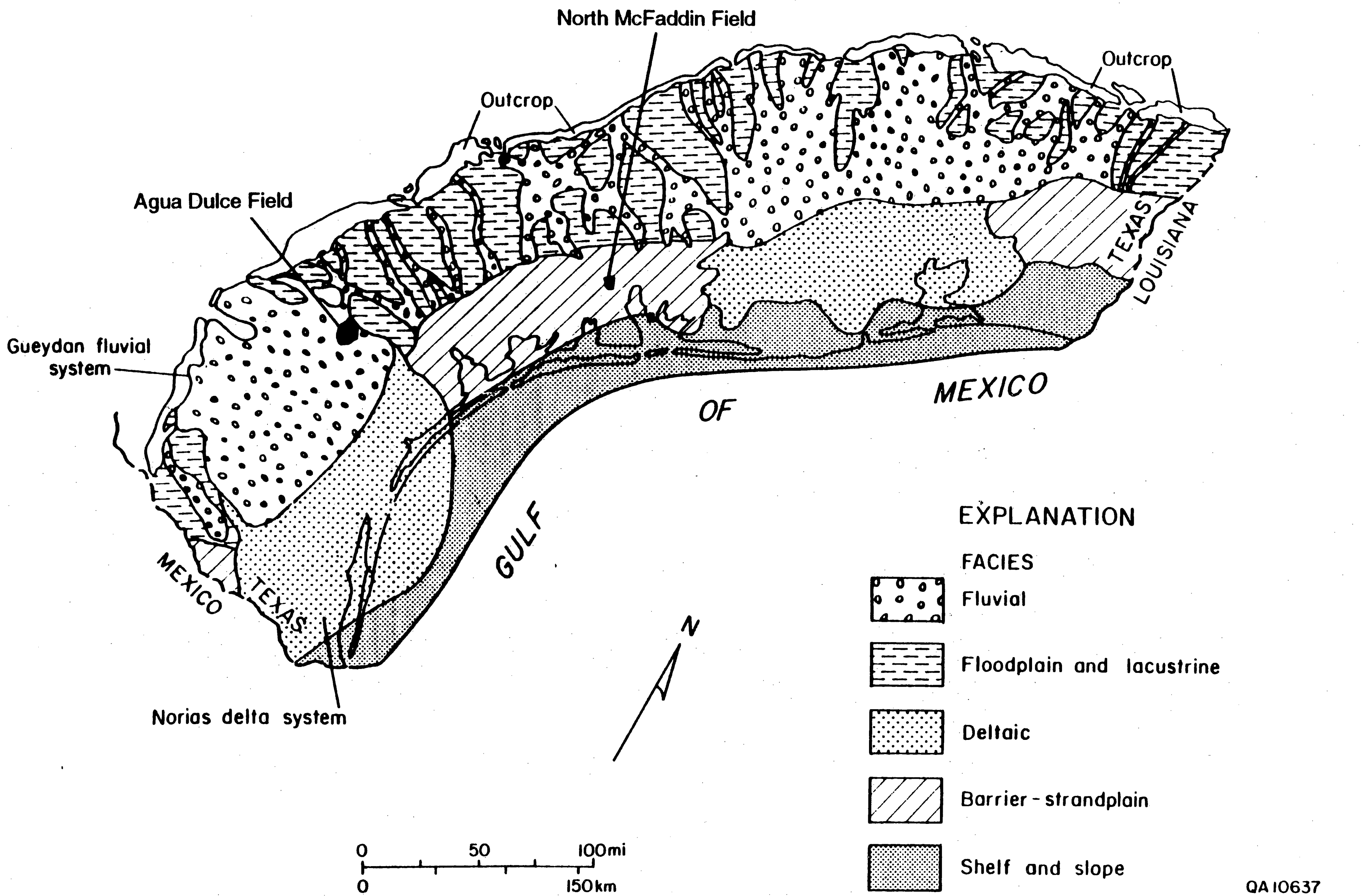


Figure 4. Depositional framework of the Frio Formation (Oligocene), and location of mini-evaluation study areas. (After Galloway and others, 1982.)

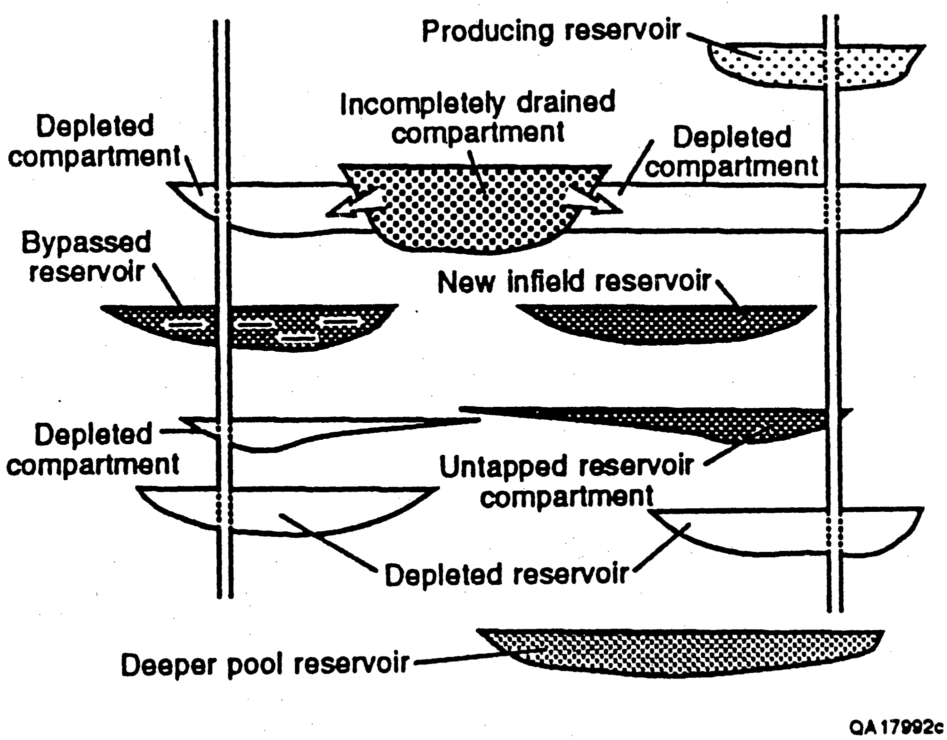


Figure 5. Major types of reservoir compartments. (After Levey and others, 1992.)

Table 1. Comparative analysis of case studies.

	N. MCFADDIN Case Study I	AGUA DULCE Case study II
SIMILARITIES		
Discovery Date	1931	1922
Development Status	Mature	Mature
Operated by	Small Independent	Small Independent
Typical Well Depth	6,500 ft	5,400 ft
Typical Well Cost	$175-275 K	$175-275 K
Lithology	Sandstone/Mudstone	Sandstone/Mudstone
*Typical Permeability Range	4-500 md	0.1-150 md
*Net/Gross Ratio	16%	21 %
*Richness (BCF/Acre)	0.7 Bcf	0.3 Bcf
*Average Completion Spacing/Ac	112	40
Typical Logging Program	AIT-LDT-CNL-GR	DIL-LDT-CNL-GR
DIFFERENCES		
Geologic Setting	FR-7	FR-4
Depositional System	Barrier/Strandplain	Fluvial
Trapping Mechanisms	Stratigraphic	Stratigraphic/Structure
Diagenetic Complications	Minimal Importance	Important
Reserve Growth Potential	Thin Bypassed and Incompletely Drained Reservoirs	Thick & Thin Bed Compartments

study area, which is to be expected because of the proximity of the case II study area to the Vicksburg Fault Zone. In contrast, reservoir genesis and primary depositional processes (stratigraphic trapping mechanisms) are considered a more important control on reservoir continuity in the case I study area.

Reservoir Attributes (Lithology, Grain Size, Porosity, and Permeability)

Both case studies are characterized by siliciclastic sandstone-mudstone lithologic sequences of Paleogene age. In both case study areas, gas-productive reservoir intervals are composed of fine- to medium-grained sandstone. The porosity of productive reservoir intervals is typically greater than 15 percent and less than 30 percent. Permeabilities measured from sidewall cores, calculated from well logs, and determined from reservoir-test analyses, range from 1 to 150 md-ft.

Reservoir Quality

In the case II study area, reservoir diagenesis has greatly affected the productivity of certain reservoir intervals. The diagenetic alteration of volcanic glass detritus in the case II study area has affected reservoir quality and produced reservoirs of low permeability (<1 md) in a manner comparable to how the middle Frio Formation in other areas of South Texas has been affected (Grigsby and Kerr, 1991; Kerr and Grigsby, 1991). Completion strategies in these lower permeability reservoirs have included hydraulic fracturing techniques to achieve adequate economic-production rates. In contrast, diagenetic processes have not adversely affected the permeability of the reservoirs from the case I study area and hydraulic fracturing techniques have not been required.

Net-to-Gross Ratio of the Productive Interval

The net-to-gross ratio for the productive gas reservoir interval for each study area was calculated using cutoffs on the computed log of sandstone/mudstone volume. In both case studies, a cutoff value of less than 20-percent mudstone (80-percent sand) was employed. For the case I study area, a net-to-gross ratio of 21.1 percent was calculated from a depth of 3,500 to 6,500 ft. The range in thickness for sand intervals was 1 to 53 ft, with a mean value of 9 ft ± 13 ft. For the case II study area, the net-to-gross ratio is 16.3 percent across the middle Frio from a depth of 4,050 to 6,750 ft. The range of thickness for sand intervals was 2 to 33 ft, with a mean value of 6 ft ± 5.2 ft.

Gross Gas Richness

Current cumulative gas production indicates a gross average gas richness of 0.7 Bcf per acre for the case I study area, compared with 0.3 Bcf per acre for the case II study area.

Operational/Technical Factors

Development Status

Both case study areas are in mature gas fields that already contain a production infrastructure. The surface well-bore density for the case I study area (average one well per 51 acres) is similar to that of the case II study area (average one well per 50 acres).

Operators

Both case study areas are operated by small independent companies based in Corpus Christi, Texas. In the case I study area, the operator purchased the existing production, property, and infrastructure. In contrast, the operator of the case II study area functions under a farm-out agreement and has no rights to preexisting production.

Well Depths

The case I study area is characterized by 36 wells, ranging in depth from 4,500 to 7,114 ft, with a mean depth of 6,392 ft. Drilling depths for the 28 wells used in the case II study area (10 wells within the Gee lease boundaries) range from 1,936 to 8,610 ft, with a mean depth of 5,366 ft. Completion-target depths for both study areas have a combined range of 3,700 to 6,700 ft.

Cost of Drilling Wells

Average well costs for the two studies are comparable, ranging from $175,000 to $225,000 per well to drill and complete, depending on completion configuration and amount of testing required during completion operations.

Logging Program

The initial logging program for both case-study areas is similar, characterized by standard electric log surveys from the 1930's to early and mid–1960's. Induction electric surveys were the normal logging suite during the 1960's to late 1980's. The development of specialized open- and cased-hole logging tools in the late 1980's and early 1990's made a critical impact on the reevaluation of undeveloped resources in both of these mature areas. In the case I study area, the induction array tool has proven essential in identifying potential bypassed gas reservoirs. Although both case studies are in mature fields, cased-hole logging technologies have not been extensively employed to reevaluate existing well bores. This is probably due to the cost associated with cased-hole logging, which can commonly exceed $20,000 per well, including well-bore preparation requirements. Current formation evaluation practices in both case-study areas include standard triple combo surveys (DIL–FDC–CNL), wireline pressure tests, sidewall cores, and fluid-sample analyses to screen completion zones.

Reserve Growth Potential

In the case I study area, reservoirs with the most potential comprise thin-bed bypassed nonassociated gas reservoirs. The SGR project focused on evaluating the more difficult thin-bed reservoirs, which were previously considered only marginally economic. In the case II study area, thin-bed and thick-bed reservoirs, in combined structural, stratigraphic, and diagenetic compartments, exist as opportunities for nonassociated secondary gas resources.

MINI-EVALUATION CASE STUDY I—NORTH MCFADDIN FIELD

by M. J. Burn, M. A. Sippel, J. M. Vidal, and J. R. Ballard

Location of the Study Area

The area under investigation comprises an 1,800-acre site termed the McFaddin "A" lease, which forms the southern half of the North McFaddin field, located approximately 13 mi south of Victoria, in southwest Victoria County, Texas (fig. 3).

Structural and Stratigraphic Framework

North McFaddin field lies in a major structural province termed the San Marcos Arch (Galloway and others, 1982), a region delineated by the northeast-southwest-trending Vicksburg and Frio Fault Zones, to the northwest and southeast, respectively (fig. 3). Northeast-southwest-oriented linear belts of growth faults and shale diapirs have been identified as important synsedimentary controls on deposition of the Frio Formation in this structural province (Bishop, 1978; Kosters and others, 1989). Furthermore, contemporaneous fault movement, associated with the reactivation of preexisting Frio faults, has also been suggested as an important control on deposition of the succeeding Oakville Formation in the San Marcos structural province (Galloway and others, 1986).

North McFaddin field is on the northwestern margin of the San Marcos Arch, near the Vicksburg Fault Zone (fig. 3). The northwest boundary of the field is almost coincident with a prominent northeast-southwest-trending fault, which probably represents a small splay fault of the Vicksburg fracture system (fig. 23). Southeasterly directed, dip-slip displacement of approximately 200 ft along this fault may be inferred. In general, North McFaddin is characterized by a north-south-trending, linear-elongate pericline that possesses closure in the midcentral and south-central parts of the field (fig. 23). This deformation is believed to have originated in response to hangingwall rollover, as opposed to shale diapirism, that accompanied movement along the fault directly northwest of North McFaddin field. Although minor faults are typically absent in the field, production data and stratigraphic correlations indicate a possible fault trending west-southwest to east-northeast, toward the south boundary of the field (fig. 23). The absence of any pronounced intrafield thickness or facies variations within the studied interval suggests a deformation of postdepositional origin.

North McFaddin field is characterized by hydrocarbon reservoirs of the Upper Frio and overlying Oakville Formations, of Oligocene and Miocene age, respectively (fig. 2). The Frio reservoirs form part of the Frio Barrier/Strandplain Sandstone oil and gas plays (Galloway and others, 1983; the FR 7 gas play of Kosters and others, 1989), and the Oakville reservoirs have been inferred as representing the Miocene Lower Coastal Plain Sandstone gas play (the MC 3 gas play of Kosters and others, 1989) (fig. 1). According to Galloway and others (1982), Frio deposition in the North McFaddin area occurred in the Greta/Carancahua barrier/strandplain system (fig. 4). Galloway and others (1986) also suggested that Miocene deposition near North McFaddin was related to the Moulton/Pointblank streamplain.

A preliminary assessment of the hydrocarbon reservoirs of North McFaddin field revealed that reservoirs at depths between approximately 3,700 and 5,200 ft represented likely candidates for incremental reserve growth. These reservoirs are briefly described below, in ascending stratigraphical order, and a representative east-west-trending cross section of the stratigraphical interval is illustrated in figure 6.

The basal part of the sequence under investigation is characterized by a composite sandstone body, up to 125 ft thick, informally termed the Sinton Sandstone. The Sinton Sandstone is overlain by a fine-grained sequence, approximately 200 ft thick, which in turn is succeeded by the 4,800-ft Sandstone Series.

The 4,800-ft Sandstone Series comprises an approximately 100-ft thick, heterolithic package of interstratified sandstones and mudstones. Individual reservoir units, typically 5 to 20 ft thick, frequently extend over the study area as laterally extensive tabular sheets (fig. 7). The 4,800-ft

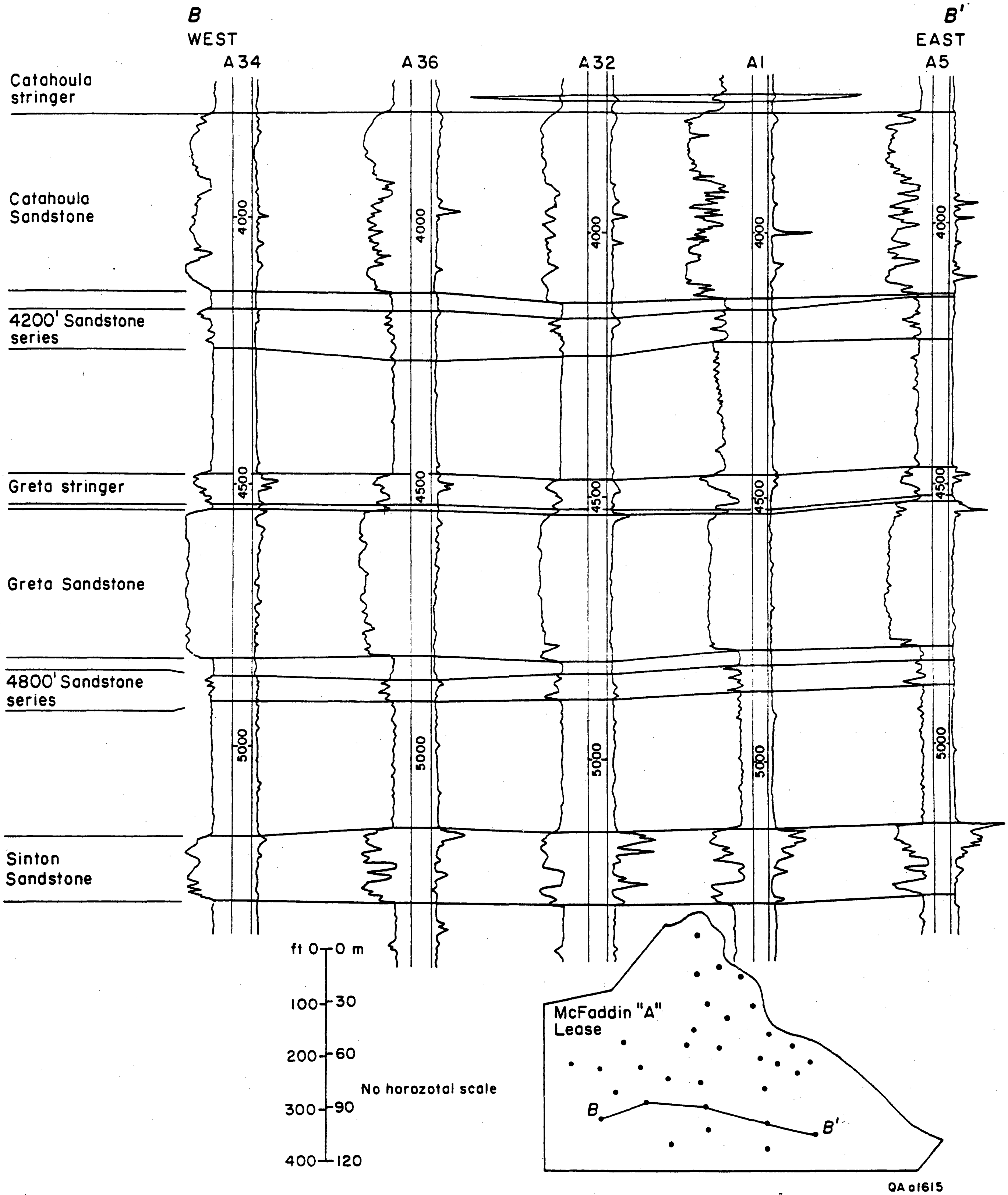


Figure 6. East-west-trending cross section B–B′ of the stratigraphic interval under investigation. Note: no horizontal scale and informal stratigraphic nomenclature adopted for case study I.

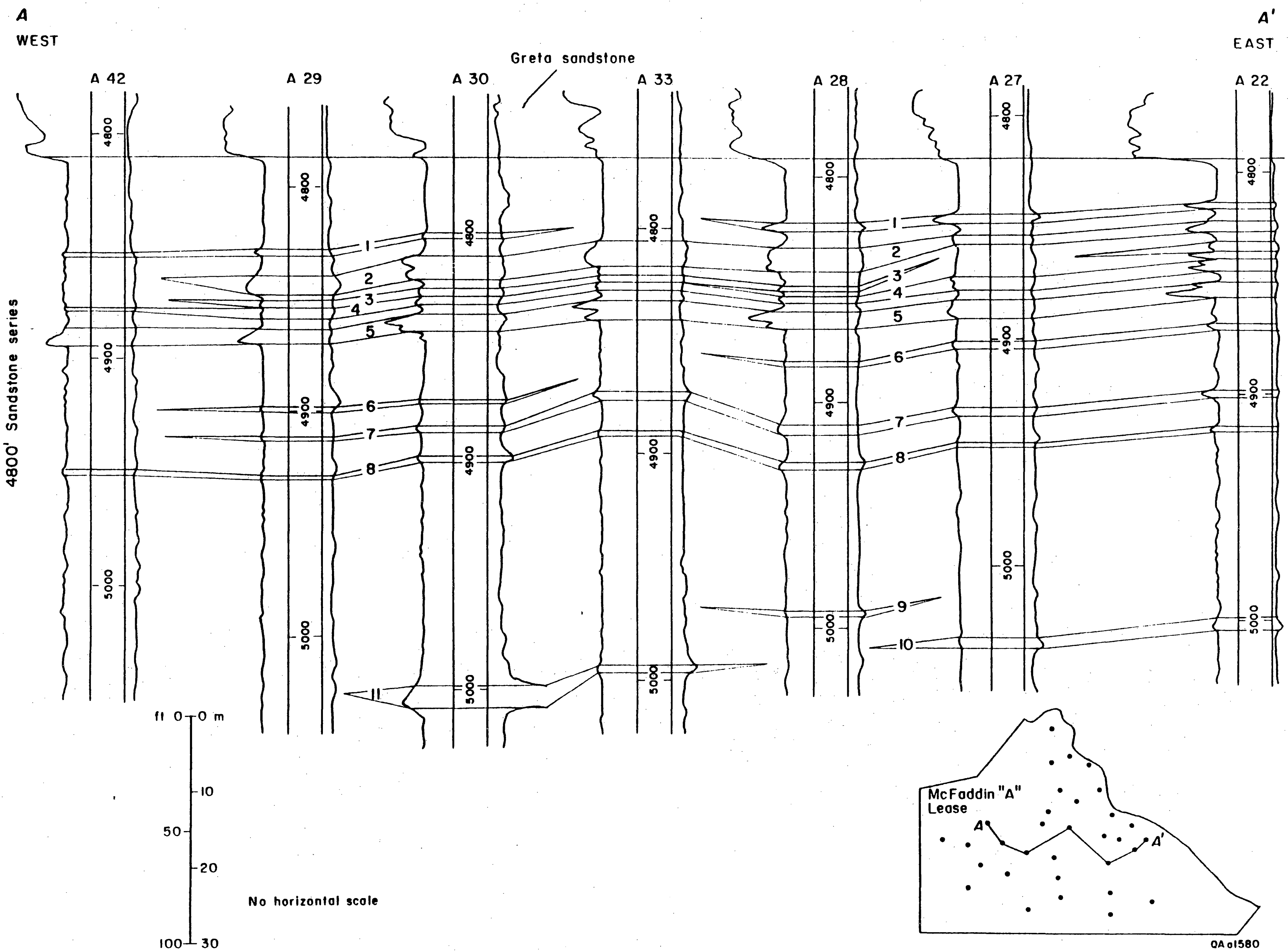


Figure 7. Detailed east-west-trending cross section A–A′ of the 4,800-ft Sandstone Series, illustrating the laterally discontinuous, tabular geometry of the individual thin-bed reservoir units from this zone. Reservoir units are numbered 1 through 11 in descending stratigraphic order. Note: no horizontal scale.

Sandstone Series is overlain by a 25-ft thick, fine-grained sequence, which in turn is succeeded by the informally termed Greta Sandstone.

The Greta Sandstone is typically 270 to 280 ft thick and is overlain by a sandstone-dominated, heterolithic sequence up to 60 ft in thickness, informally known as the Greta Stringer. The Greta Stringer is succeeded by a fine-grained sequence, up to 250 ft in thickness, whose basal parts form the Anahuac Shale. This sequence in turn is overlain by a heterolithic package termed the 4,200-ft Sandstone Series.

The 4,200-ft Sandstone Series, typically 75 ft in thickness, comprises interstratified sandstones and mudstones. Individual reservoir units typically form laterally extensive sheets 5 to 20 ft thick over the study area (fig. 8). The 4,200-ft Sandstone Series is overlain by a 25-ft-thick, fine-grained sequence, which in turn is succeeded by the informally termed Catahoula Sandstone.

The Catahoula Sandstone, displaying thicknesses around 360 ft, is overlain by a laterally discontinuous sandstone, up to 15 ft thick, known as the Catahoula Stringer. Worthy of note is the striking similarity, in terms of thickness and character, of the sequences that occur between the tops of the Sinton Sandstone and Greta Stringer and the tops of the Greta Sandstone and Catahoula Stringer (fig. 6).

Whole-core sedimentological data to test the proposed sedimentary models of the Frio and Oakville Formations (Galloway and others, 1982, 1986) are absent. However, in these models the Sinton and Greta Sandstones probably represent single- and multistory proximal shoreface deposits, respectively. Because the Catahoula Sandstone overlies the Anahuac Shale (fig. 6), it forms the lowermost part of the Oakville Formation. According to Galloway and others (1986) and Kosters and others (1989), the Oakville Formation in the North McFaddin area was deposited by small fluvial systems on a mud-dominated coastal plain. However, this model is inconsistent with the thickness and geometry of the Catahoula Sandstone. Our study suggests that the Catahoula Sandstone was deposited in a fashion analogous to the underlying Greta Sandstone, which reflects multistory-stacked proximal shoreface deposits. Therefore, the lowermost parts of the Miocene in

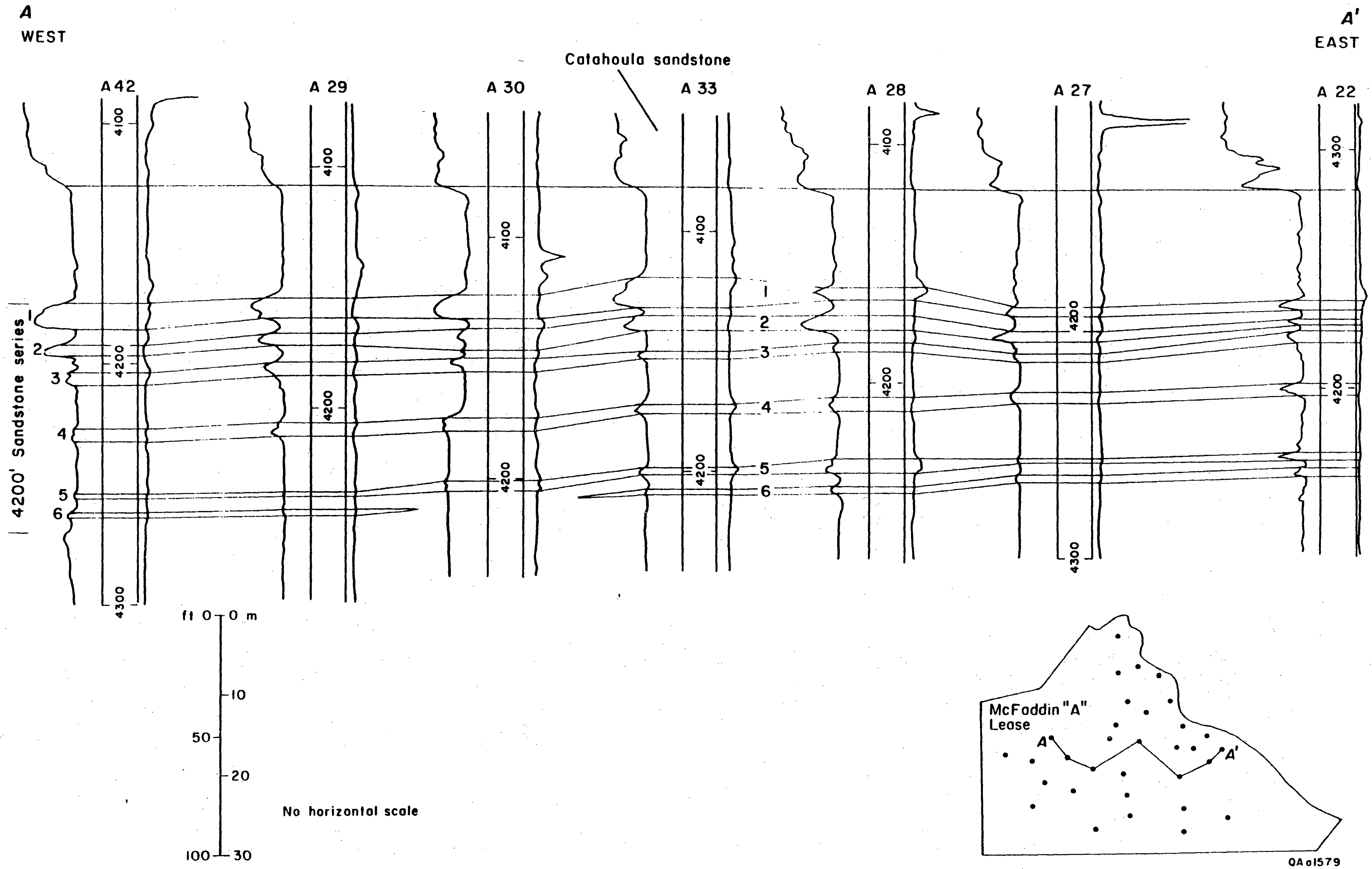


Figure 8. Detailed east-west-trending cross section A–A′ of the 4,200-ft Sandstone Series, illustrating the laterally discontinuous, sheetlike geometry of the individual thin-bed reservoir units from this zone. Reservoir units are numbered 1 through 6 in descending stratigraphic order. Note: no horizontal scale.

the North McFaddin area probably form part of the Matagorda Barrier/Strandplain System rather than the Moulton/Pointblank streamplain (see Galloway and others, 1986).

Although Galloway and others (1982) indicated the importance of contemporaneous faulting in the localization of Frio shoreface depocenters, the negligible thickness variation in the Sinton, Greta, and Catahoula Sandstones indicate that the effects of synsedimentary tectonism cannot be established in the study area (fig. 6). Controls on proximal shoreface stacking patterns are probably intimately related to rates of sediment supply and relative base-level change (compactional/tectonic subsidence and/or eustasy).

If the Greta/Carancahua barrier/strandplain model (Galloway and others, 1982) is adhered to, the sequence context of the Greta and Catahoula Stringers suggests deposition related to phases of shoreface transgression. The Catahoula and Greta Stringers probably comprise the deposits of either ebb-tidal channel/delta complexes or washover fans. A sedimentological interpretation of the 4,200- and 4,800-ft Sandstone Series remains problematical. Galloway (1986) interpreted comparable sandstone beds as distal shoreface deposits. A similar depositional origin would help to explain the sandstone bodies in the North McFaddin area, although their position relative to paleoshoreline remains ambiguous.

Core photograph data examined from reservoirs considered comparable to those of the 4,200- and 4,800-ft Sandstone Series (4,115- to 4,124-ft depth, Quintana well No. 294, Refugio County) reveal highly bioturbated, interstratified sandstones and mudstones of subequal thicknesses, approximately 1 to 2 ft. It is important to note that individual reservoir units are not the products of discrete depositional events, but of multiple, superposed depositional episodes. Furthermore, these deposits are interpreted as allochthonous, instead of autochthonous, in origin and are believed to have been transported into the shelf setting, as opposed to being reworked within it. Brief periods of storm activity are envisioned as the driving force behind the episodic flushing of shoreface sediment into the shelf environment.

Many ancient examples of similar storm-related shelf deposits ("tempestites") have been described (for example, Brenchley and others, 1979; Hamblin and Walker, 1979; Galloway, 1986).

Although storms are often cited as the generating agents for cross-shelf transport, considerable debate exists as to the actual processes of sediment entrainment, transport, and deposition. Following Hayes' (1967) classic model, many authors assumed shore-normal sediment transport, caused by "storm-surge retreat/storm ebb," as a valid and fundamental storm process. However, the mechanics of this model and, by inference, the interpretation of the many authors who relied on Hayes' model as an analog for their ancient storm sequences, have been questioned (Morton, 1981; Swift, 1984, p. 35–36; Swift and Niedorada, 1984; Walker, 1984, p. 46).

In summary, the thin-bed reservoir intervals of the 4,200- and 4,800-ft Sandstone Series are interpreted to represent deposition from shelf-density currents associated with storm events. Bioturbation indicates intense biogenic reworking following the emplacement of sand beds by storm-related current activity. The interstratified fine-grained material indicates that significant fair-weather periods separated each discrete event.

Production and Development History

North McFaddin field was originally discovered by Transwestern Oil and Gas in 1931, with the completion of Transwestern No. A-1 McFaddin in a Miocene-age reservoir informally termed the 3,500-ft Sandstone. Transwestern conducted limited development of the field through the 1930's and mid-1950's. Nine wells were drilled to relatively shallow depths (ranging from 4,500 to 5,200 ft) and, in general, gas production predominated. The primary completion targets during this initial development period were reservoirs of Upper Frio/Oakville age, the Catahoula Sandstone (3,800 ft), the Greta Stringer (4,500 ft), and the Sinton Sandstone (5,200 ft).

The second phase of field development occurred when Sun Oil purchased the lease in the mid-1950's and conducted an intensive drilling/development program during the 1960's and 1970's. This program included the deepening of preexisting Transwestern wells and the drilling of 24 wells from the 1960's to the early 1980's. These wells typically penetrated depths ranging from 6,000 to 7,000 ft; all wells were deeper than those previously drilled by Transwestern. In general, gas production was achieved by the recompletion of formerly identified reservoirs, the completion of previously unencountered or unidentified reservoirs, and the development of reservoirs at depths greater than previous Transwestern well penetrations. In the latter case, the reservoirs are both oil and gas productive, and oil production within North McFaddin field was largely a consequence of this phase of field development. Sun Oil produced gas from 35 reservoirs and oil from 20 reservoirs in North McFaddin field, all of Frio and Oakville age.

In 1984, the North McFaddin lease was sold to Kamlok Oil and Gas. Other than the maintenance of preexisting levels of production, from this date the area experienced negligible activity until the lease was acquired in January 1992 by Anaqua Oil and Gas, its present owners. Anaqua's activity to date has included drilling three wells, reentry and subsequent completion of previously bypassed gas reservoirs in one well, and the restoration of gas production in two previously shut-in gas wells. Current targets include attic gas recovery from the Catahoula, Greta Stringer, and Sinton Sandstones, in addition to completing some of the formerly bypassed reservoirs of the 4,200- and 4,800-ft Sandstone Series. Oil reservoirs also form important recompletion opportunities, typically at depths of 5,300 to 7,000 ft.

Gas production by reservoir in North McFaddin is summarized in appendix 2. To date, none of the wells have penetrated the underlying Vicksburg Formation. Thus, the deep potential of the study area is difficult to evaluate because of the absence of data. The few scattered wells that penetrate the Vicksburg in the surrounding area generally indicate a sandstone-poor section, but the Champlin A-20 McFaddin well (total depth, 10,500 ft), 1 mi to the south of the North McFaddin "A" lease, was completed at a depth of 6,800 ft as a Vicksburg gas well. The well, with a potential recovery of 3 Mmcf/d, is currently flowing at 1 Mmcf/d.

Resource Analysis

Preliminary screening indicated that reservoirs between the Sinton Sandstone (5,200 ft) and the Catahoula Stringer (3,700 ft) deserved detailed evaluation, given their important contribution to cumulative gas production in the North McFaddin area (appendix 2).

Petrophysical analyses of the Greta Stringer, Sinton and Catahoula Sandstones in the A-58 and A-59 wells, drilled April 1992 and August 1992, respectively, indicated that remaining gas production potential was characterized by strong water-drive mechanisms. Although these reservoirs obviously form important recompletion targets for attic gas recovery, a secondary reservoir-screening process (involving input from the field operator) targeted the laterally discontinuous, thin-bed reservoirs of the Catahoula Stringer (3,700 ft) and the 4,200- and 4,800-ft Sandstone Series as an important potential source of incremental reserves (figs. 6 and 7). Preliminary formation evaluation, combined with historical production data analysis, indicated that a number of these thin-bed reservoir units had been bypassed or incompletely drained during original field development.

The thin-bed reservoir units provide important targets for secondary gas recovery, not only because their potential remained untargeted during primary field development, but also because their geometries may form subtle stratigraphic traps. Reasons for the underdevelopment of this potential resource probably included the application of a development strategy that focused on other opportunities. However, it is probable that development was controlled in part by technological constraints associated with the analysis and evaluation of thin-bed reservoirs through the use of electric or induction-electric logs. Not only were the thin-bed units difficult to recognize using conventional logging devices (typically lacking vertical resolution of less than 6 ft), but their potential productivity was also difficult to assess because they were frequently characterized by ambiguous or pessimistic log responses.

Recent developments in the wireline-logging industry have included new tools whose limits of vertical resolution are far superior to those of their induction-log predecessors. In the two most recently drilled wells in North McFaddin field (A-59 and A-60), logged cooperatively by Anaqua Oil and Gas and the SGR project, the comparatively recent Array Induction Tool (AIT)* allowed identification and analysis of potentially productive thin beds that were undoubtedly overlooked using conventional induction devices. The AIT provides vertical resolution of about 1 to 2 ft and, combined with enhanced porosity processing, permits a much more rigorous evaluation of the potential of thin-bed zones.

Thin-bed reservoir drive mechanisms are mixed volumetric pressure depletion and water drive. Gas recovery from water-drive reservoirs can be much less than that from pressure-depletion drive reservoirs (Craft and Hawkins, 1959). On the basis of an average initial water saturation of 45 percent and a residual gas saturation of 30 percent, a recovery factor of 45 percent was estimated for reservoirs characterized by strong water-drive mechanisms. In contrast, the recovery factor for volumetric pressure-depletion drive reservoirs was estimated at 80 percent, based on an average initial pressure of 2,000 psi and an abandonment pressure of 400 psi.

The evaluation of the thin-bed resource in North McFaddin field commenced with preliminary log evaluation of the potential productivity of each thin-bed unit from the 3,700-, 4,200-, and 4,800-ft stratigraphic zones. Units characterized by resistivity values of less than 1.2 ohm-m were eliminated from further study. Detailed correlation and rigorous mapping of the remaining units were carried out to determine their geometry and to identify faults. This process culminated in the construction of net thickness maps for each thin-bed unit and, in some cases, the delineation of their external geometries (stratigraphic terminations). By selecting a suitable widespread marker horizon for each of the 3,700-, 4,200-, and 4,800-ft stratigraphic zones, and by determining the marker horizon's elevation relative to sea level at each well location, structural contour maps were constructed for each stratigraphic zone in the study region.

Other parameters considered relevant to the study included relative spontaneous potential and resistivity. Relative spontaneous potential is defined as the ratio of spontaneous potential to static

*The use of firm and brand names in this report is for identification purposes only and does not constitute endorsement by the Bureau of Economic Geology.

spontaneous potential (SP/SSP). Values of SSP were estimated from the water-saturated portions of the Greta and Catahoula Sandstones. Resistivity values from induction-electric logs were determined from the deepest resistivity device available and were accepted as "true" resistivity. With electric logs it was necessary to use lateral measurements as approximate values of "true" resistivity. Log parameters were interpreted as approximate measures of petrophysical properties. Relative SP was used as an indicator of potential permeability and reservoir quality. Sidewall core data supported the interpretation that high SP/SSP values corresponded with zones of high permeability. In general, resistivity was interpreted as a measure of gas saturation, high resistivity values corresponding to high gas saturation. High resistivity values corresponding to zones of low porosity were determined by recognizing severely reduced SP values for the equivalent zone. These anomalous values of resistivity were filtered out prior to final analysis. Because resistivity values are neither synchronous nor absolute for previously productive units, and will be intimately linked in a complex manner according to the timing, volume, and location of gas production, the resistivity parameter was considered appropriate in the general delineation of prospective areas of interest, rather than individual well recompletion targets. By constructing contour maps of relative SP and resistivity values, and by comparing these maps with historical gas-production data, it was possible to estimate the minimum values of these parameters that defined previously productive reservoir units. SP/SSP values greater than 0.2 and resistivity values greater than 1.5 ohm-m were determined to represent reliable guideline figures.

The potentially productive areal limits of each thin-bed unit were delineated by superposing the contoured maps of relative SP, resistivity, net thickness, and structure, and integrating these maps with well-test production, wireline formation tests, and sidewall core data.

Log Evaluation Techniques

All available resistivity logs were used during the study, including electric logs spanning the 1930's to 1950's, conventional induction-electric logs of the 1960's, and phasor induction and array induction logs from the recently drilled wells. Most of the wells were characterized by electric logs possessing short normal, long normal, and lateral curves. For example, figure 9 illustrates the electric log of well A-28. Short (16-inch spacing) and long (64-inch spacing) normal resistivity curves are presented in the second track as solid and dotted lines, respectively, and the lateral resistivity curve is shown in the third track. Note the resistivity measurements recorded by these devices for the thin-bed units at depths of 4,822, 4,910, 4,926, and 4,992 ft. The long normal device (dotted line) records low resistivity that may mislead the analyst to conclude that the thin-bed units are water bearing. However, these low resistivity values are apparent because unit thickness (approximately 24 to 48 inches) is less than the spacing of the long normal measuring device (64 inches). The lateral curve provides a more reliable indicator of "true" resistivity in the thin-bed units. Although the thin-bed units at depths of 4,926 to 4,930 ft and 4,992 to 4,994 ft are characterized by pessimistic long normal resistivity, high lateral resistivity peaks (>2.7 ohm-m) suggest that these zones are potentially productive. This interpretative use of the lateral device, however, is inappropriate in an evaluation of beds greater than or equal in thickness to the spacing of the lateral device (216 inches). In these cases, the long normal device provides a more accurate measure of resistivity. Because low resistivity zones may also be characterized by anomalously high lateral resistivity peaks, caution is advised in using the lateral device to identify potential pay zones. Composite logs, combining induction and electric log suites, confirmed the value of the lateral device for assessing the "true" resistivity of the thin-bed units. The deep induction curve was used to select potential zones of interest in wells measured with induction log suites. However, it is important to note that the vertical resolution of the conventional induction device is typically restricted to 5 to 6 ft, unlike the AIT, which effectively resolves beds of 1 to 2 ft in thickness.

In comparing array induction, phasor induction, and electric logs, the AIT represents the best device for recognizing and evaluating thin-bed units. Not only does the AIT provide greater vertical resolution, it also shows five different depths of investigation (10, 20, 30, 60, and 90 inches), which allows the analyst a greater understanding of the invasion profile. For example, at depths of 4,200 to 4,206 ft and 4,874 to 4,878 ft in well A-59 (figs. 10a and 10b), thin gas-bearing zones may be

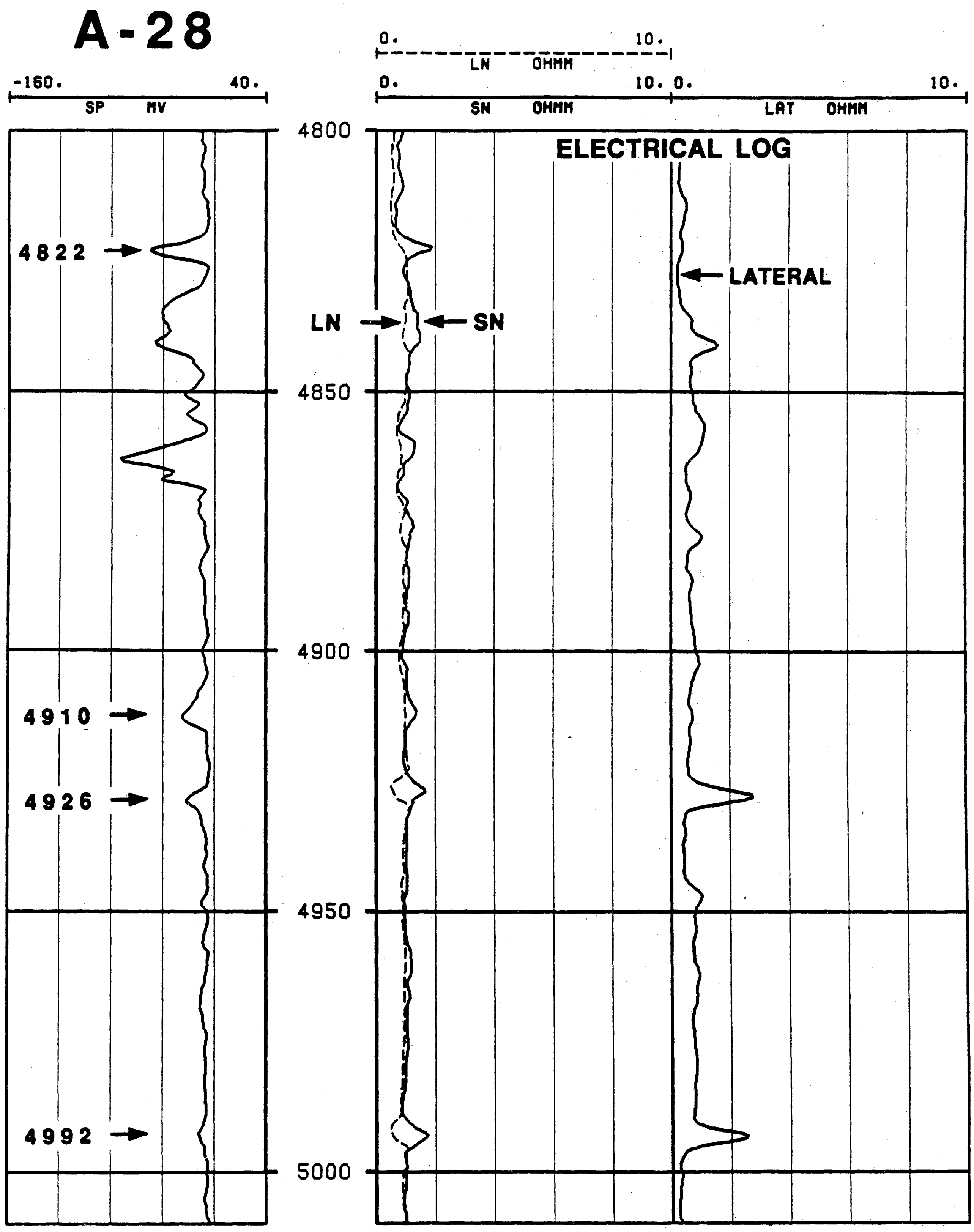


Figure 9. Electrical log of well A-28 illustrating the short normal, long normal, and lateral resistivity measurements of thin-bed units from the 4,800-ft Sandstone Series. Note that the lateral curve provides the most reliable indicator of "true" resistivity for thin-bed zones.

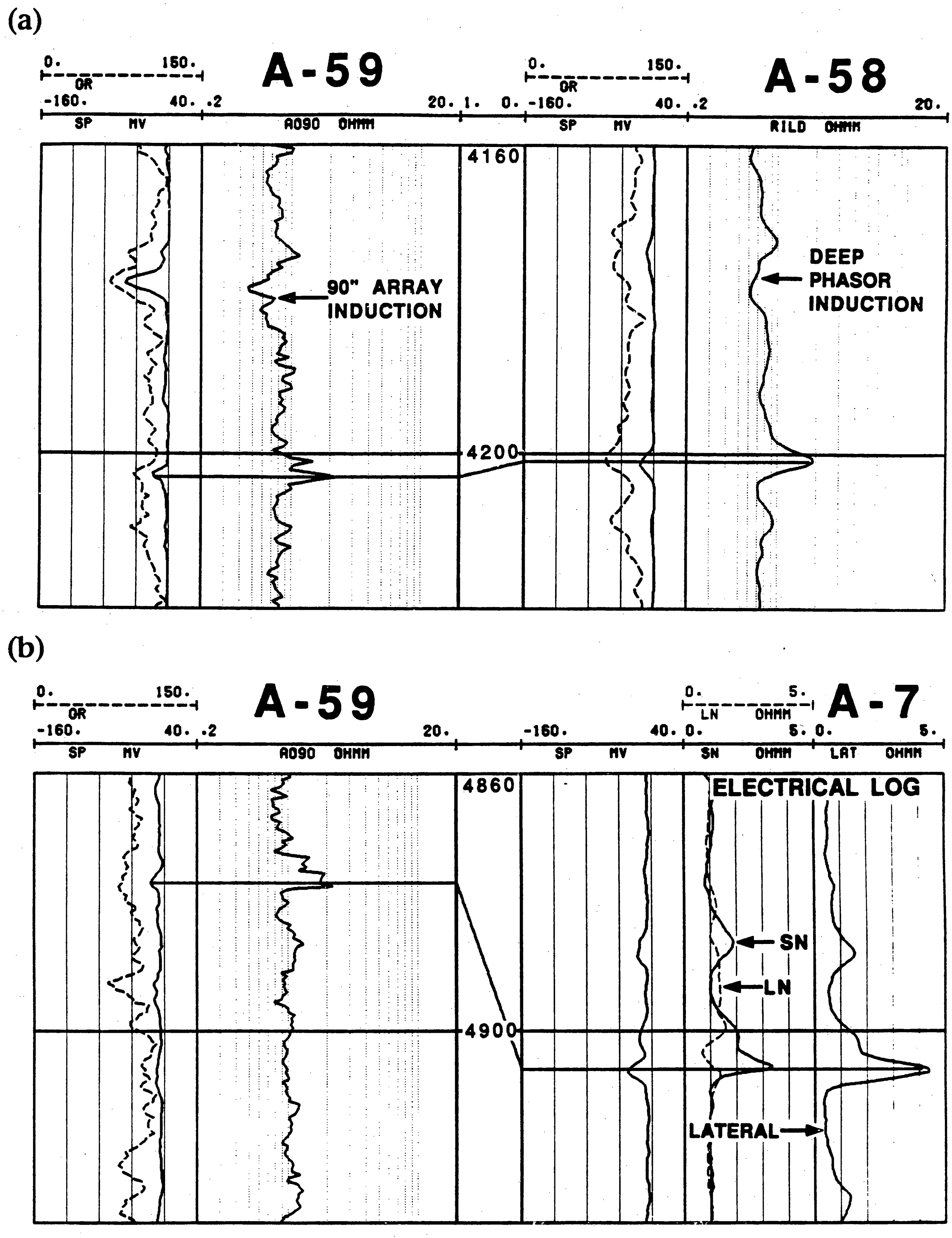


Figure 10. Comparison of array induction, phasor induction, and electrical logs for recognizing and evaluating thin-bed potential: (a) array induction versus phasor induction log of correlative zone illustrates the superior resolution of the AIT when compared with the PIL, even following enhancement processing; (b) array induction versus electrical log of correlative zone illustrates the improved resolution of the AIT is even more striking when compared with electrical logs.

easily identified and analyzed for hydrocarbon content using the AIT. By comparison, the correlative zone at a depth of 4,199 to 4,203 ft in the A-58 well lacks the clarity of resolution in the phasor induction log, even following enhancement processing (fig. 11a). The improved resolution of the AIT is even more striking when compared with electric logs. For example, the array induction log of the thin-bed unit at a depth of 4,874 to 4,878 ft in well A-59 illustrates the markedly improved resolution of the correlative zone recorded on the electric log of the nearby A-7 well (fig. 11b).

Engineering Techniques

Volumetric methods, supplemented by material-balance calculations and pressure data, were used to estimate potential original gas in place for each prospective thin-bed unit. This procedure enabled reservoir ranking by volume and remaining development potential. Appendix 1 shows the formula for determining the original gas in place.

Reservoir pore volumes were determined for each thin-bed unit using appropriate values of potentially productive areal extent and mean net thickness. A net/gross factor of 85 percent, determined by examining core photographs of thin-bed reservoirs that were considered comparable to those of North McFaddin, was applied to mean net thickness values to account for nonreservoir facies within reservoir intervals. Average porosity values of 25 percent and water saturation values of 45 percent were determined from modern log petrophysical data available for the thin-bed units evaluated as potentially gas productive in the A-58 and A-59 wells. The initial gas volume factor (Bgi) for each thin-bed unit was determined from published correlations, using a gas gravity of 0.58 (air = 1) and calculated values of temperature and original reservoir pressure. Bottomhole temperature was determined using a temperature gradient of 1.7°F/100 ft and a mean surface temperature of 70°F. Estimates of original reservoir pressure for each thin-bed unit were based on a pressure gradient of 0.433 psi/ft. This pressure gradient was calculated from initial wellhead shut-in pressures and wireline pressure tests obtained from several reservoirs in the A-58, A-59, and

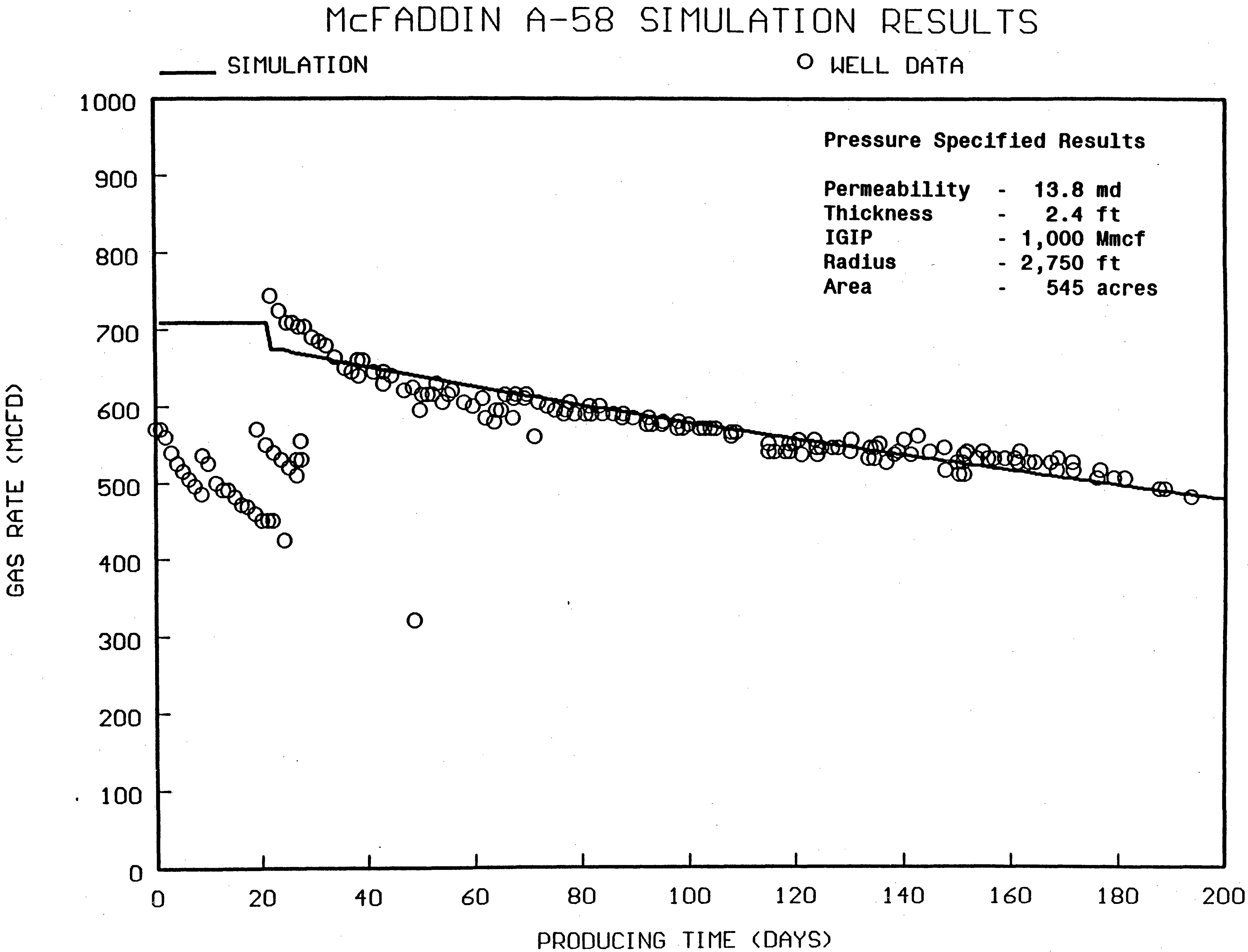


Figure 11. Production- and simulation-history match for the 4,200-ft zone No. 5 reservoir completion in the A-58 well.

A-60 wells. Performing material-balance calculations for original gas in place using available pressure data enabled volumetric and material-balance original gas in place estimates to be compared. Because reservoir pressure adjusted for compressibility (p/z) declines in a linear manner with respect to production, plots of p/z versus cumulative gas production were extrapolated to determine either original gas in place or potential reserves at particular abandonment pressures for volumetric pressure-depletion drive reservoirs. Table 2 summarizes the reservoir parameters and the results of reservoir evaluation for original gas in place and remaining gas in place. Eleven thin-bed units were evaluated to determine the size of the original and remaining resource. Estimated resources for individual units ranged from 150 to greater than 7,000 Mmcf under the North McFaddin "A" lease. The original gas in place was estimated to be 27.4 Bcf. The recoverable gas in place was estimated to be 20.3 Bcf. Combined cumulative production from the thin-bed units prior to January 1, 1992, was 8.1 Bcf. Remaining reserves are estimated to be 12.2 Bcf (table 2).

The productivity and drainage capabilities of two recent thin-bed completions were assessed using a radial-flow simulator (the 4,200-ft No. 5 reservoir at a depth of 4,199 to 4,203 ft in well A-58 and the 4,800-ft No. 8 reservoir at a depth of 4,896 to 4,906 ft in well A-7). Simulations enabled quantification of potential contacted gas reserves and permeability thickness (kh). Production histories of the recent completions are too short to allow an analysis of ultimate recoveries by rate-decline curve methods. Contacted gas for the A-58 and A-7 completions was estimated at 1,000 Mmcf and 400 Mmcf, respectively, and effective kh was determined to be 30 and 50 md-ft, respectively. Other thin-bed completions, with less available data, were characterized by comparable productivity and kh values. Values of effective permeability to gas (kg) range from 5 to 20 md.

The radial-flow, finite-difference simulator utilized a series of concentric rings to describe the reservoir around a well bore. Gas viscosity and compressibility values used during simulation exercises were based on published correlation methods of hydrocarbon gas gravity, temperature, and pressure. Net thickness, porosity, and water saturation were based on the average values determined from log evaluation in the potentially productive area of each reservoir. Initial reservoir pressures were established from wireline formation tests and wellhead shut-in pressures.

Table 2. McFaddin potential resource estimates as of January 1992.

Reservoir Parameters							Resource Estimates				Resource Category
Reservoir	Depth ft	H Gross ft	A Area acre	Po psi	Temp deg F	Bgi scf/rcf	OGIP Mmcf	Rcvrbl GIP Mmcf	Cum Prod Mmcf	Remain Reserves Mmcf	Reservoir Terminology
3700	3715	6.8	843	1602	133	109.8	3204	2564	931	1633	Incompletely drained
4200 No. 1	4140	9.2	1263	1797	141	121.6	7193	4360	4360	0	Depleted
4200 No 5	4215	2.4	1377	1819	141	123.2	2073	1658	0	1658	Bypassed
4200 No. 6	4250	3.0	80	1820	142	125.0	153	122	0	122	Bypassed
4800 No. 1	4805	3.6	809	2061	151	136.3	2021	1617	521	1096	Incompletely drained
4800 No. 2	4820	10.5	740	2065	151	136.6	5404	4323	0	4323	Untapped
4800 No. 5	4845	8.3	120	2078	152	137.5	697	340	340	0	Depleted
4800 No. 7	4890	3.2	539	2100	152	139.0	1221	976	0	976	Bypassed
4800 No. 8	4910	2.6	1027	2107	153	139.4	1895	1516	0	1516	Incompletely drained
4800 No. 9	4980	2.1	482	2135	154	141.3	728	583	0	583	Bypassed
4800 No. 11	5010	4.5	850	2143	154	141.9	2763	2211	1911	300	Incompletely drained
					Total*		27,352	20,269	8063	12,207	

OGIP = 43.56*h*A*phi*(1-Sw)*Bgi

Temperature gradient = 1.7 deg F per 100 ft
Pressure gradient = 0.433 psi per ft
Gas gravity = 0.58 (air =1)
Porosity = 25%
Water Saturation = 45%
Net/Gross = 85%

*Totals may not equal sum of components due to independent rounding.

Both rate- and pressure-specified history-matching exercises were performed. Rate-specified matches used flowing rate data as input, and the simulator calculated wellhead flowing or shut-in pressures. When flowing pressure data are used as input, the simulator calculated flowing rates. To match the declining trend of reported daily flowing rates and pressures supplied by the operator, drainage radius and effective permeability were varied appropriately. For example, the simulated history match for the 4,200-ft No. 5 reservoir completion in the A-58 well is shown in figure 11. Late-time flow-rate trends were matched with a permeability of approximately 14 md, a drainage area of 545 acres, and a flowing reservoir pressure of about 1,050 psi.

The lack of successive shut-in pressure-buildup test data and the use of wellhead pressures to estimate flowing pressures limited the simulation exercises. Simulation exercises assumed no well-bore damage or stimulation, and considered pressure depletion as the only reservoir drive mechanism.

Examples of Incremental Resources

To illustrate the spectrum of secondary gas resource types in North McFaddin field, three thin-bed reservoirs were selected as representative examples and are discussed below. (See appendix 1 for discussion of the remaining eight thin-bed units.) Each thin-bed reservoir discussed below is accompanied by appropriate maps of relative spontaneous potential, resistivity, net thickness, and structure. Delineated through superposition of these parameters, maps of the interpreted potentially productive limits of these reservoirs are also provided. Figure 12 illustrates the location of wells in North McFaddin field.

3,700-Ft Zone (Catahoula Stringer Reservoir)—Incompletely Drained

Prior to the purchase of North McFaddin field by Anaqua Oil and Gas, the Catahoula Stringer reservoir was completed at depths of 3,704 to 3,706 ft in well A-16 and had a reported gas production of 931 Mmcf from 1963 to 1976 (figs. 13 through 17). Production from this zone in A-16

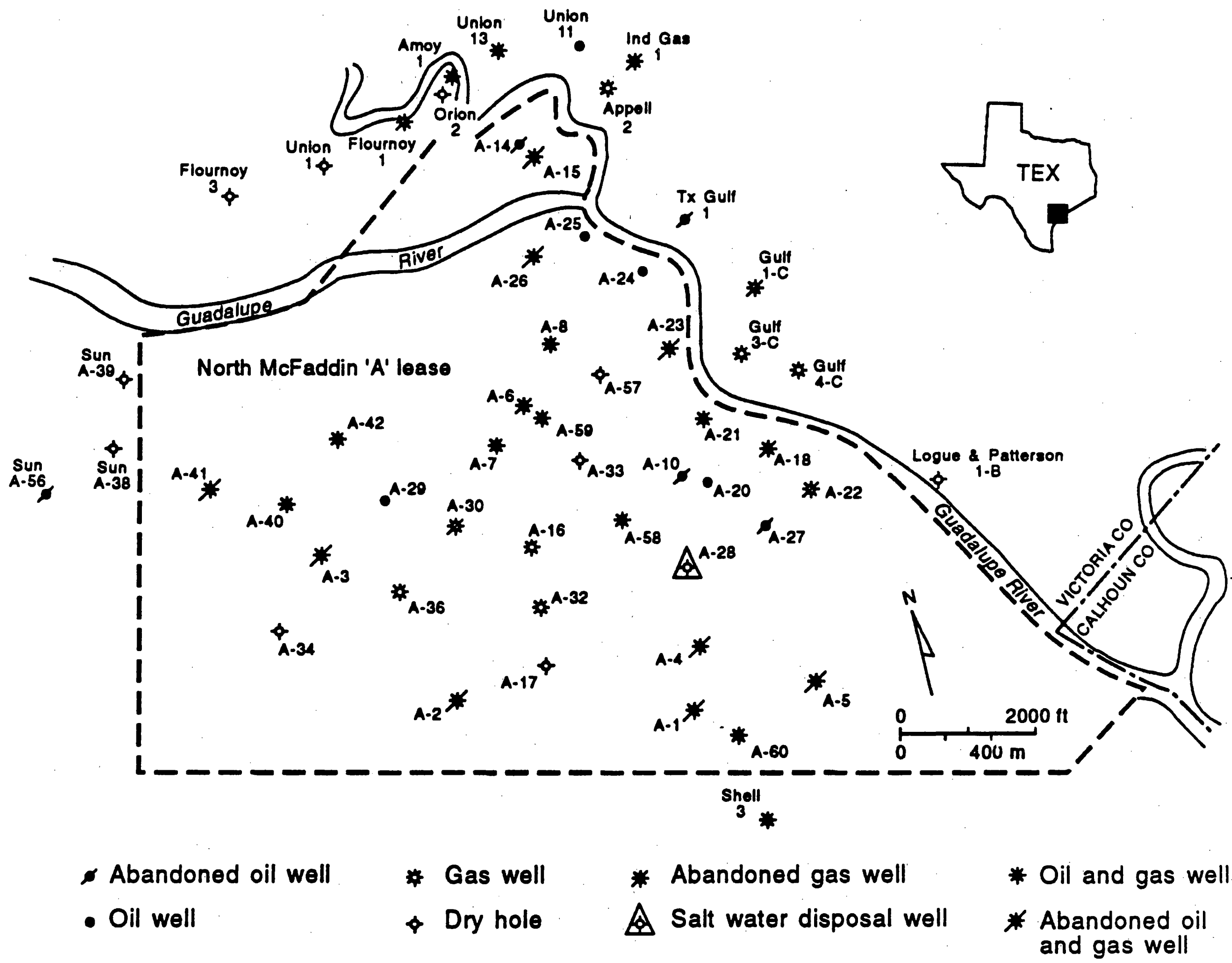


Figure 12. Location of wells in case I study area (North McFaddin field).

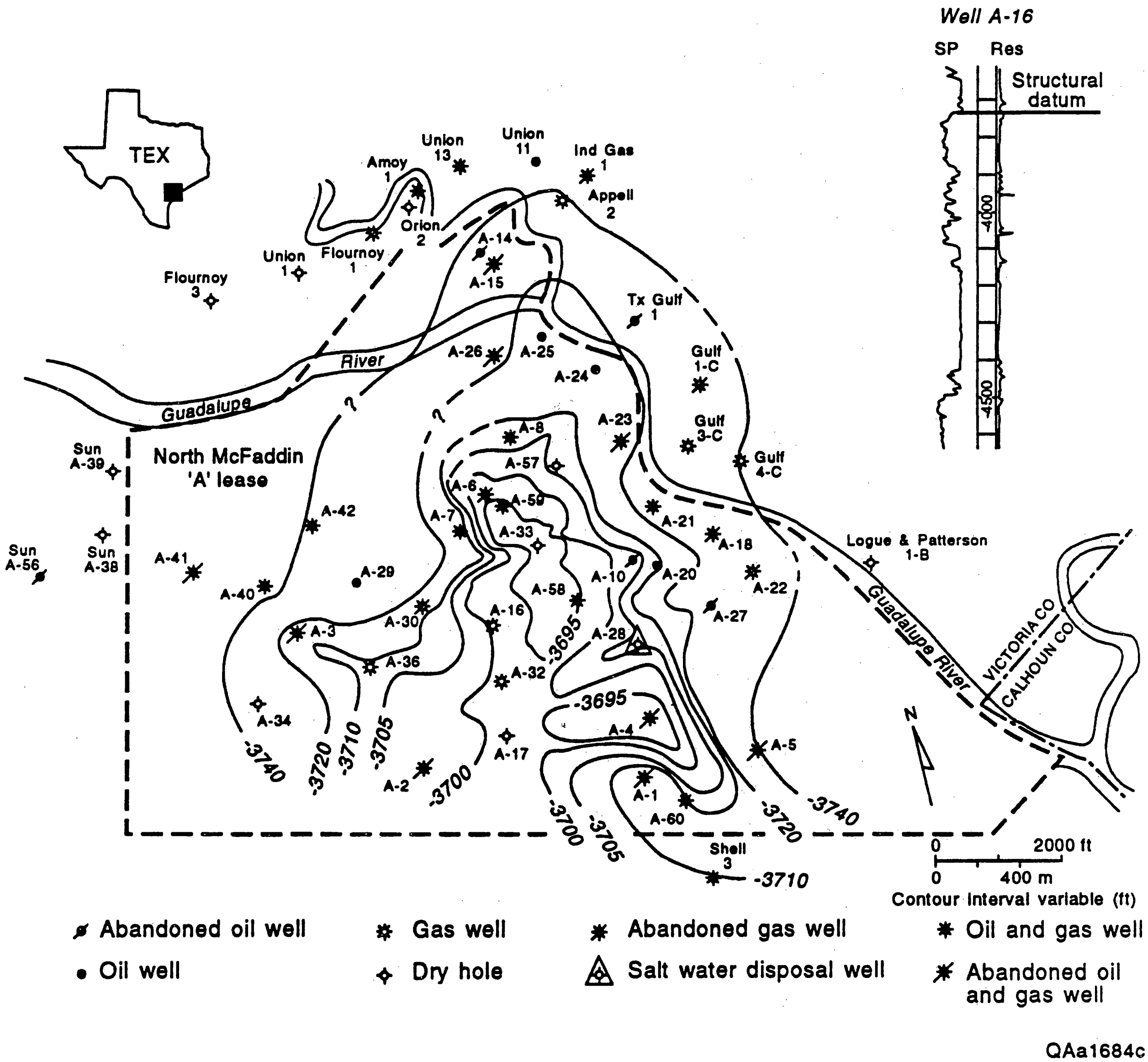


Figure 13. Structure-contour map for the 3,700-ft zone. Depths relative to sea level in feet.

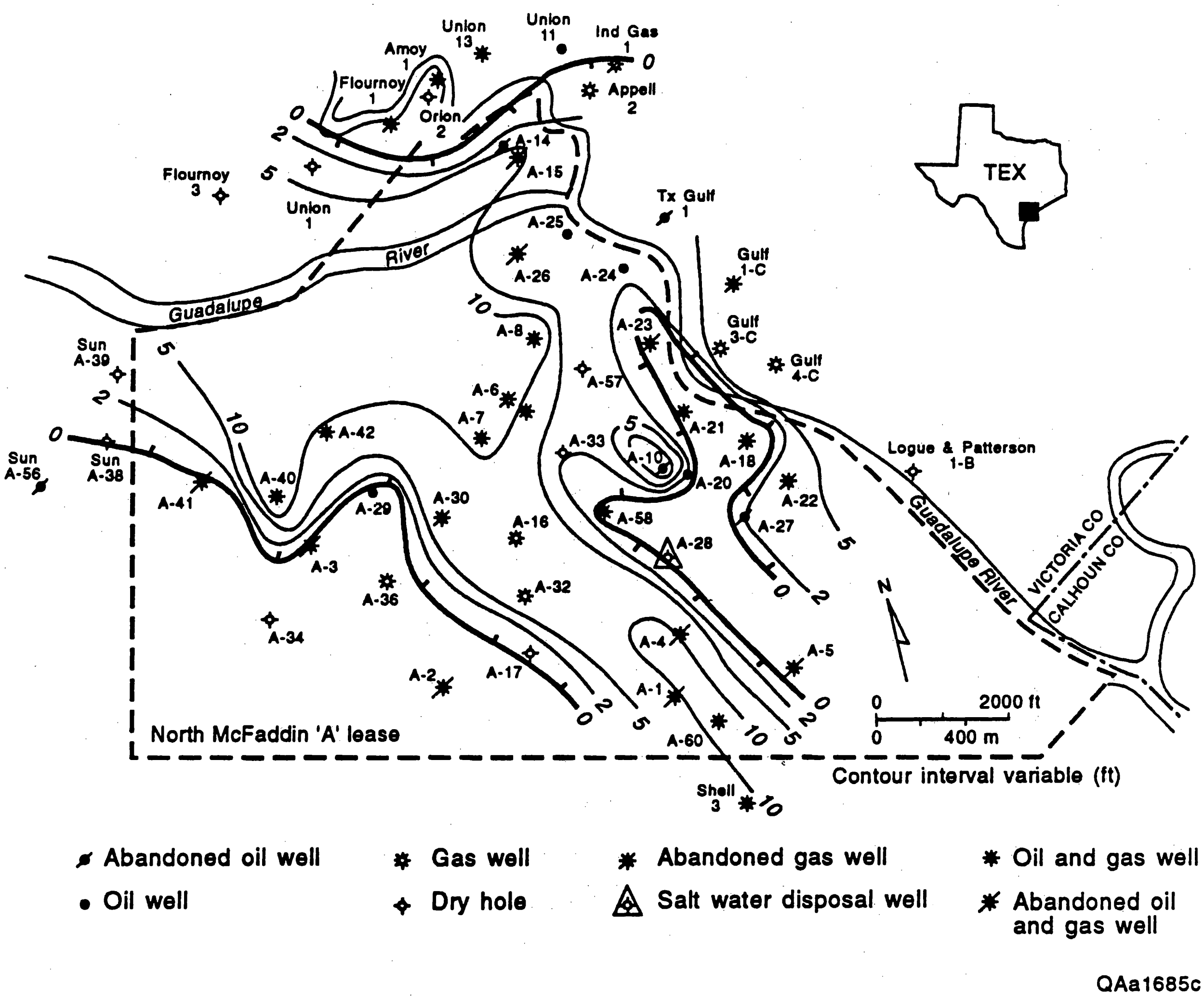


Figure 14. Net-thickness contour map of the 3,700-ft zone Catahoula Stringer reservoir. Units = ft.

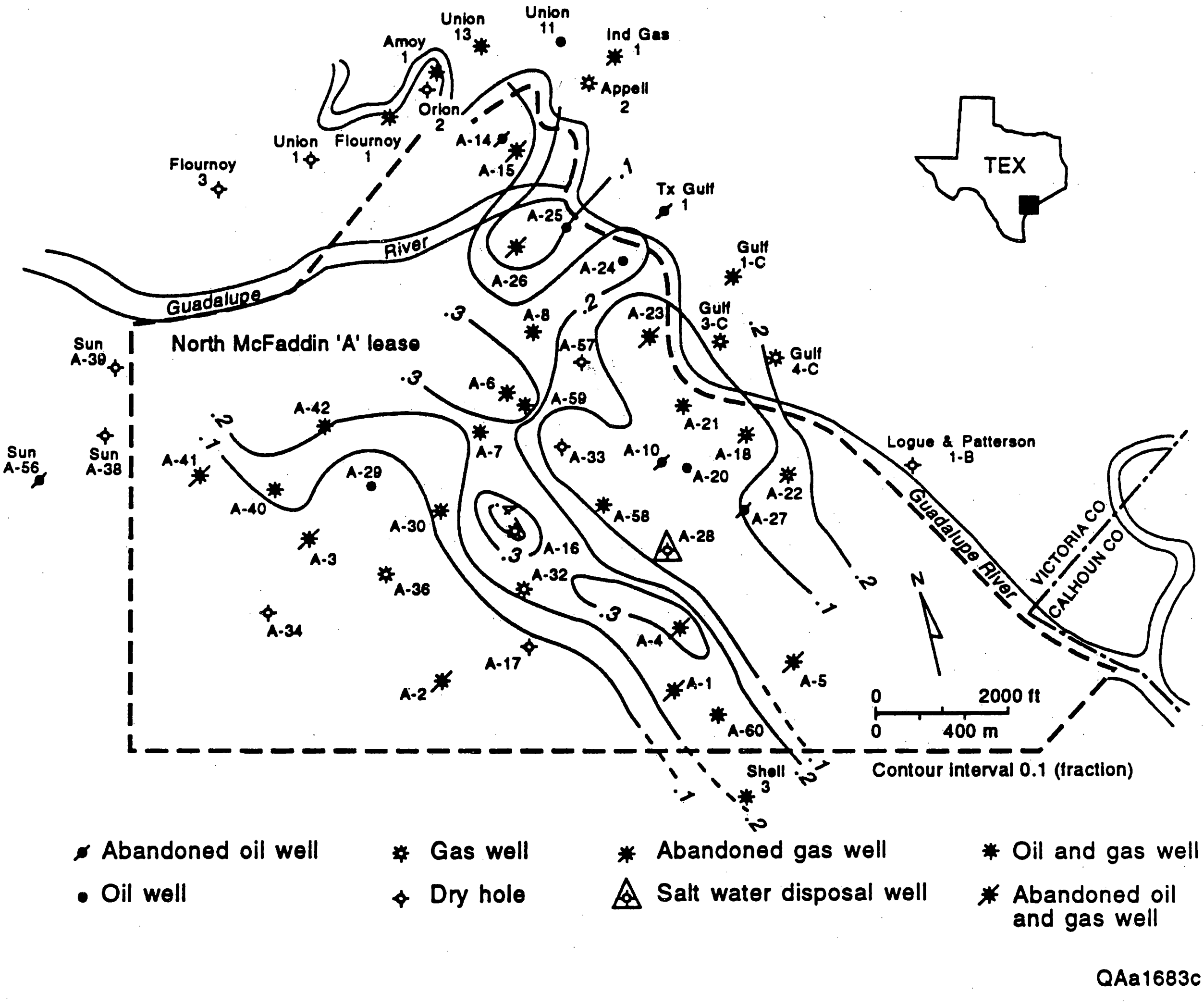


Figure 15. Relative spontaneous potential contour map of the 3,700-ft zone Catahoula Stringer reservoir. Units = fraction.

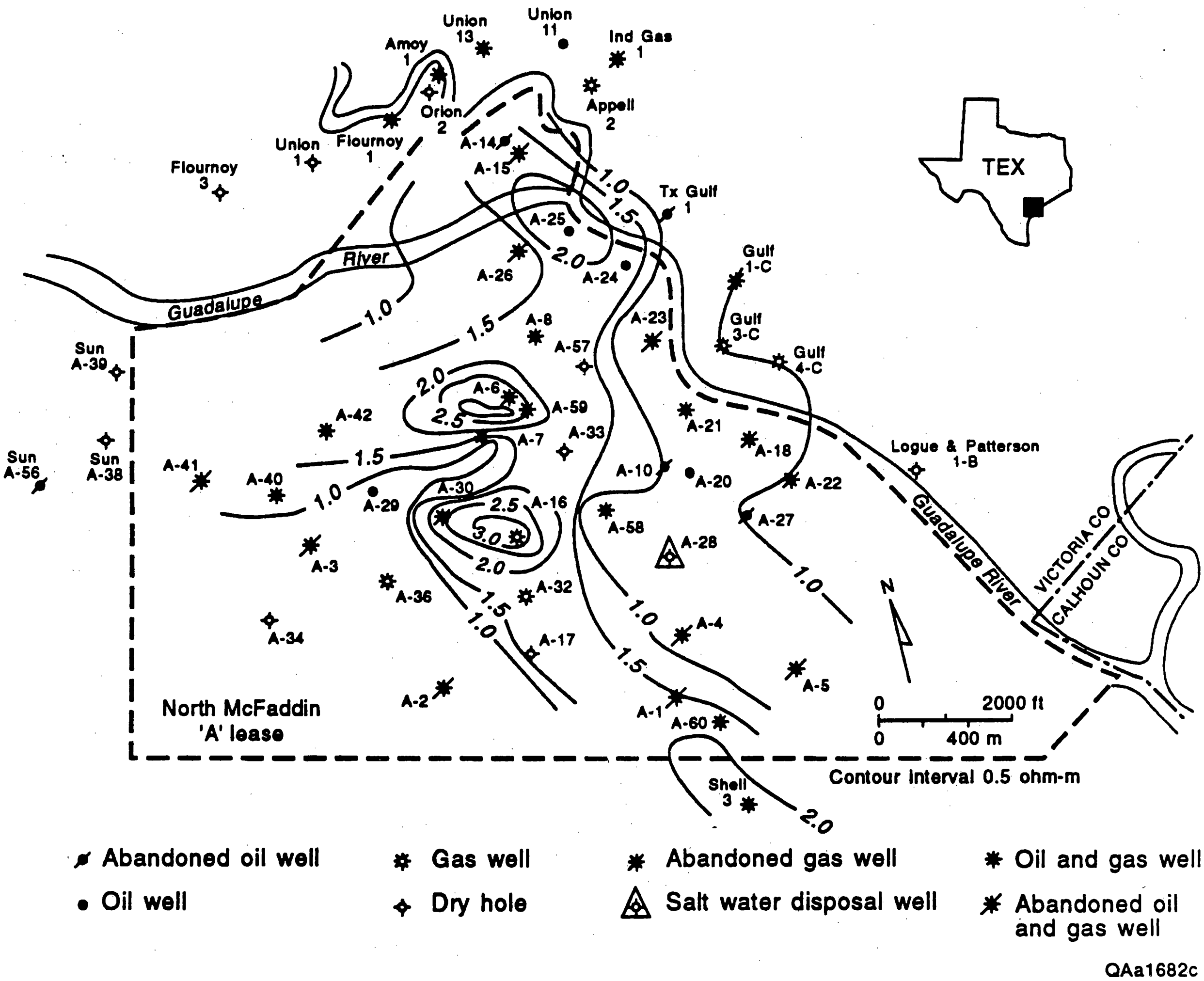


Figure 16. Deep-resistivity contour map of the 3,700-ft zone Catahoula Stringer reservoir. Units = ohm-m.

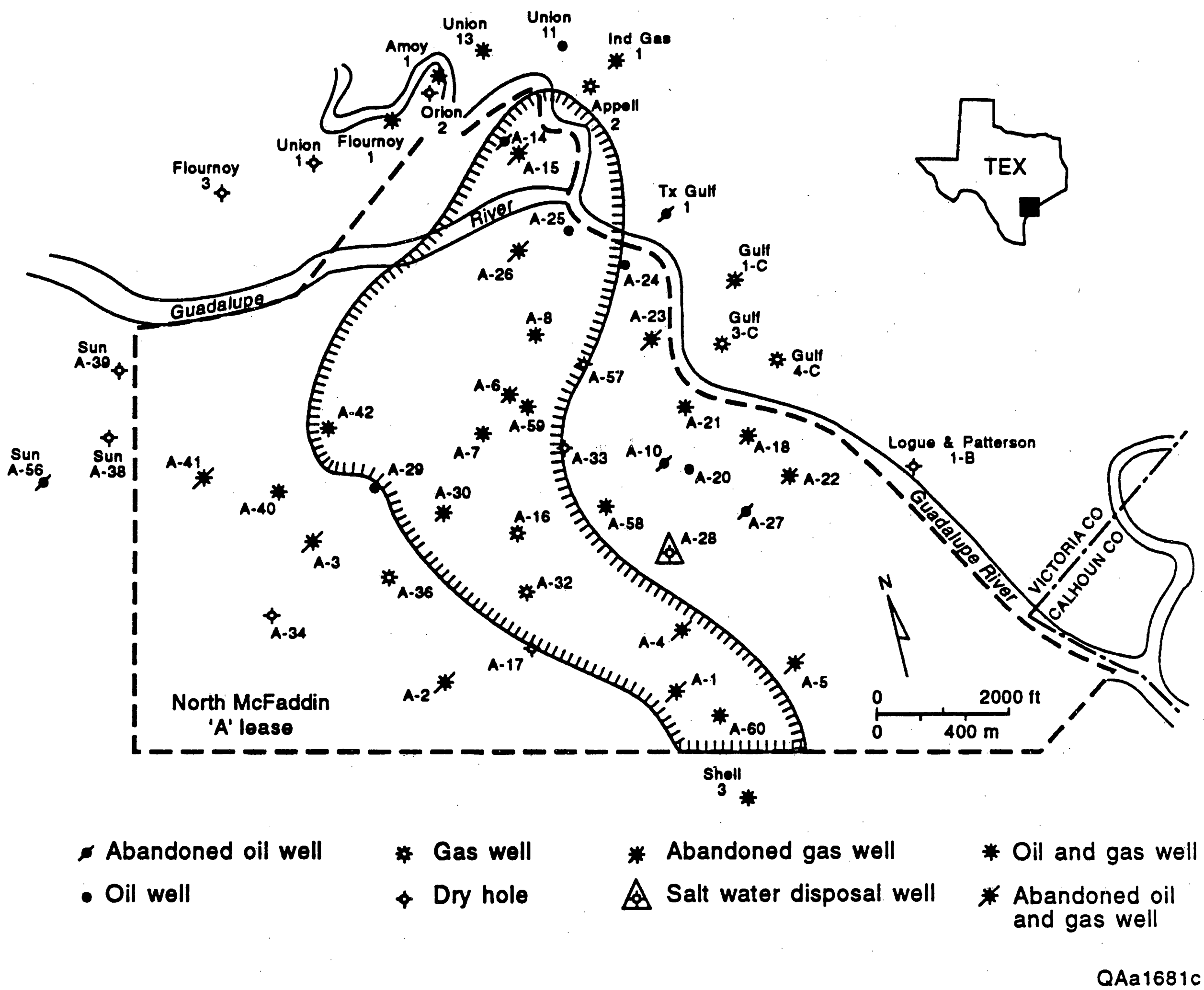


Figure 17. Potentially productive limits of the 3,700-ft zone Catahoula Stringer reservoir. Refer to table 1 for values of areal extent and average thickness.

was restored by Anaqua Oil and Gas, and cumulative production from February 1, 1992, to November 1, 1992, was 56 Mmcf. In addition, this reservoir was completed at depths of 3,742 to 3,748 ft in the Shell No. 3 well, located off the North McFaddin "A" lease, approximately 1,300 ft south of well A-60 (fig. 12). A cumulative gas production of 1,914 Mmcf in the Shell No. 3 well was reported from 1953 to 1980.

The interpreted potentially productive areal extent of this reservoir in North McFaddin is 843 acres, with an average thickness of 6.8 ft (fig. 17). The original gas in place was estimated at 3,204 Mmcf using an initial reservoir pressure of 1,603 psi. Using wireline tools, the reservoir pressure was tested in well A-59 on August 21, 1992, and well A-60 on November 28, 1992. Although the wireline pressure test for this reservoir in well A-59 recorded 1,054 psi, test data indicate that this pressure reading was not fully stabilized and was still building. The wireline pressure test for this reservoir in well No. A-60 recorded nearly 1,200 psi. Wireline pressure data indicate significant remaining gas reserves. Petrophysical log evaluation supports this, indicating 4.5- and 3-ft gas pay zones for the reservoir in wells A-59 and A-60, respectively.

The comparable wireline pressure measurements at the A-59 and A-60 wells indicate that the reservoir may be in communication under the McFaddin "A" lease and that significant gas reserves remain. Material-balance calculations, using the cumulative production from the A-16 well of 931 Mmcf and the depletion of the reservoir pressure from 1,602 to 1,200 psi, indicate an original gas in place of nearly 3,500 Mmcf. This volume is in agreement with the volumetrically determined original gas in place, estimated at 3,204 Mmcf. The remaining recoverable gas is estimated at 1,633 Mmcf (table 3).

The current reservoir pressure of 1,200 psi also indicates that the reservoir has a pressure-depletion drive mechanism. If the reservoir had a strong water drive, the reservoir pressure would have recharged to original pressure conditions after a shut-in time of 16 yr (the last year of production on the lease was 1976). If this reservoir has a low-permeability or small-volume aquifer, there could be partial pressure recharge resulting from slow water influx. However, under active gas production, the reservoir would still behave as a reservoir with depletion-drive character. A unit

Table 3. Case I—North McFaddin field: risked reserves.

Reservoir/ Zone	Original GIP Mmcf	Rcvrbl GIP Mmcf	Cum Prod Mmcf	Remain Reserves Mmcf	Dvlpd Remain Reserves Mmcf	Undvlpd Remain Reserves Mmcf	Dvlpd Risk Factor	Undvlpd Risk Factor	Risked Dvlpd Mmcf	Risked Undvlpd Mmcf	Risked Total Mmcf
Risked Reserves Summary as of January 1992											
3700	3204	2564	931	1633	1633	0	66%	66%	1078	0	1078
4200 No. 1	7193	4360	4360	0	0	0	0%	0%	0	0	0
4200 No. 5	2073	1658	0	1658	800	858	100%	66%	800	566	1366
4200 No. 6	153	122	0	122	0	122	0%	33%	0	40	40
4800 No. 1	2021	1617	521	1096	0	1096	0%	66%	0	723	723
4800 No. 2	5404	4323	0	4323	0	4323	0%	33%	0	1427	1427
4800 No. 5	697	340	340	0	0	0	0%	0%	0	0	0
4800 No. 7	1221	976	0	976	0	976	0%	33%	0	322	322
4800 No. 8	1895	1516	0	1516	320	1196	100%	66%	320	789	1109
4800 No. 9	728	583	0	583	0	583	0%	33%	0	192	192
4800 No. 11	2763	2211	1911	300	300	0	66%	66%	198	0	198
Total*	27,352	20,269	8,063	12,207	3,053	9,154			2,396	4,060	6,456

*Totals may not equal sum of components due to independent rounding.

recovery factor of 80 percent would still be a valid assumption, and the remaining reserves would still be estimated at 1,633 Mmcf.

The A-16 well was reworked and the 3,700-ft reservoir returned to production in February 1992. The well was flowing at about 500 mcf/d with a flowing wellhead pressure of about 600 psi after the workover. The remaining recoverable gas is estimated at 1,644 Mmcf. The A-16 well would require 25 yr to produce this gas if the production rate declined exponentially from 500 to 50 mcf/d. If the rate remained constant at 500 mcf/d, the time required to produce the potential recoverable gas would be nearly 9 yr.

The calculated time to recover the reserves from the 3,700 ft reservoir indicates that other completions in the reservoir should be made to deplete the reservoir quickly and efficiently. The reservoir could be completed in either the A-59 or A-60 wells, where log evaluations and wireline tests indicate probable commercial potential. The 3,700-ft reservoir could also be one of several thin-bed objectives at a drilling location midway between the A-4 and A-17 wells. An overlay of well-log parameter maps of the thin-bed reservoirs (figs. 13 through 16) indicates that a well drilled at this location would have an opportunity to encounter several previously bypassed or incompletely drained thin-bed reservoirs. This SGR opportunity is recommended in appendix 5.

4,200-Ft Zone (No. 5 Reservoir)—Bypassed

Prior to the completion in the A-58 well by Anaqua Oil and Gas, this reservoir was bypassed during primary development (figs. 18 through 22). Logging tool resolution allowed identification of this reservoir as bypassed. Anaqua completed this well at a depth of 4,198 to 4,203 ft in April 1992. An open-hole wireline pressure test recorded an original reservoir pressure of 1,820 psi in March 1992. The reservoir was brought to production without stimulation treatment, and initial production rates were 745 mcf/d, with a flowing well-head pressure of 1,220 psi. Cumulative production through November 1, 1992, was 107 Mmcf. The potentially productive areal extent of

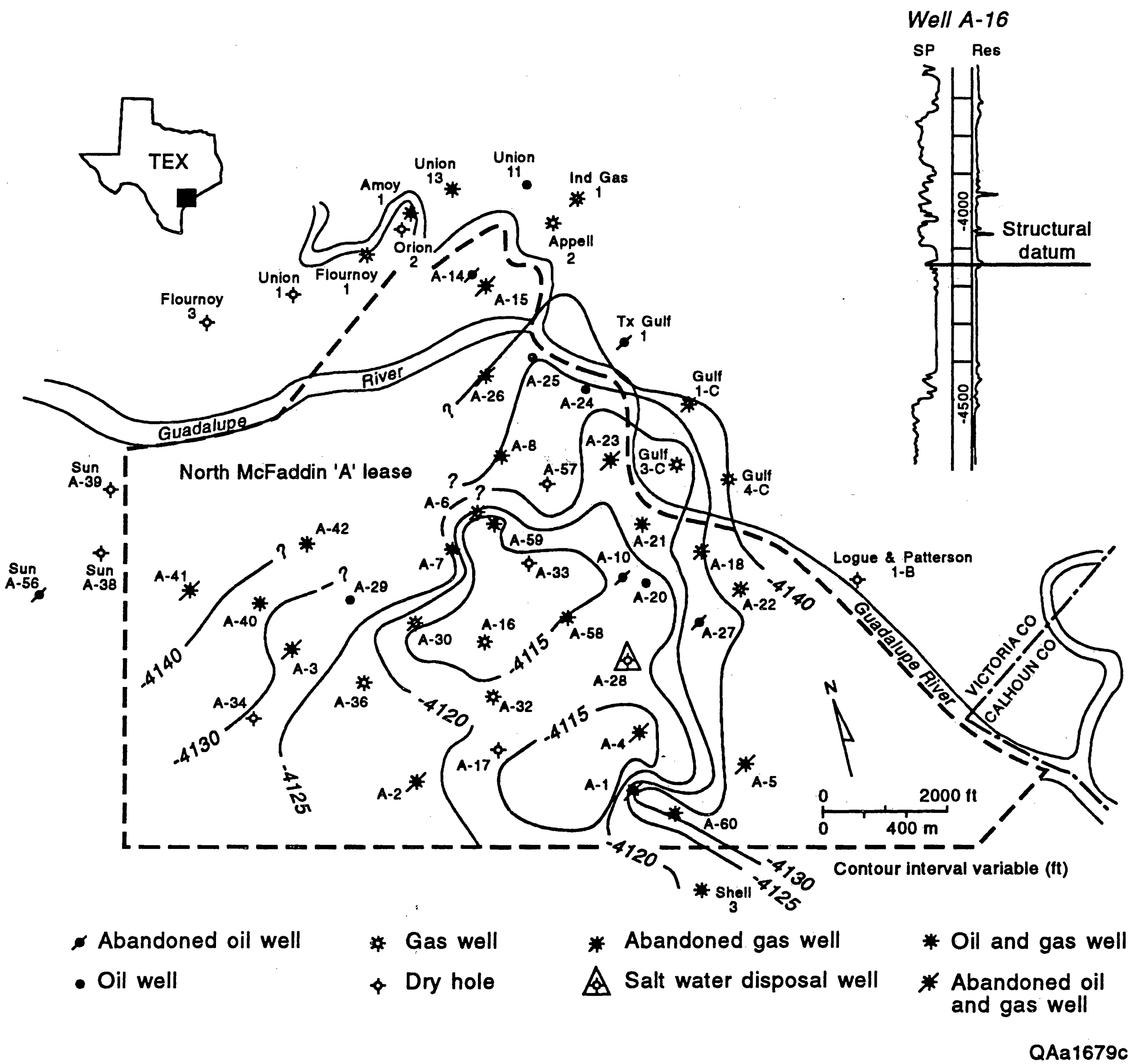


Figure 18. Structure-contour map for the 4,200-ft zone. Depths relative to sea level in feet.

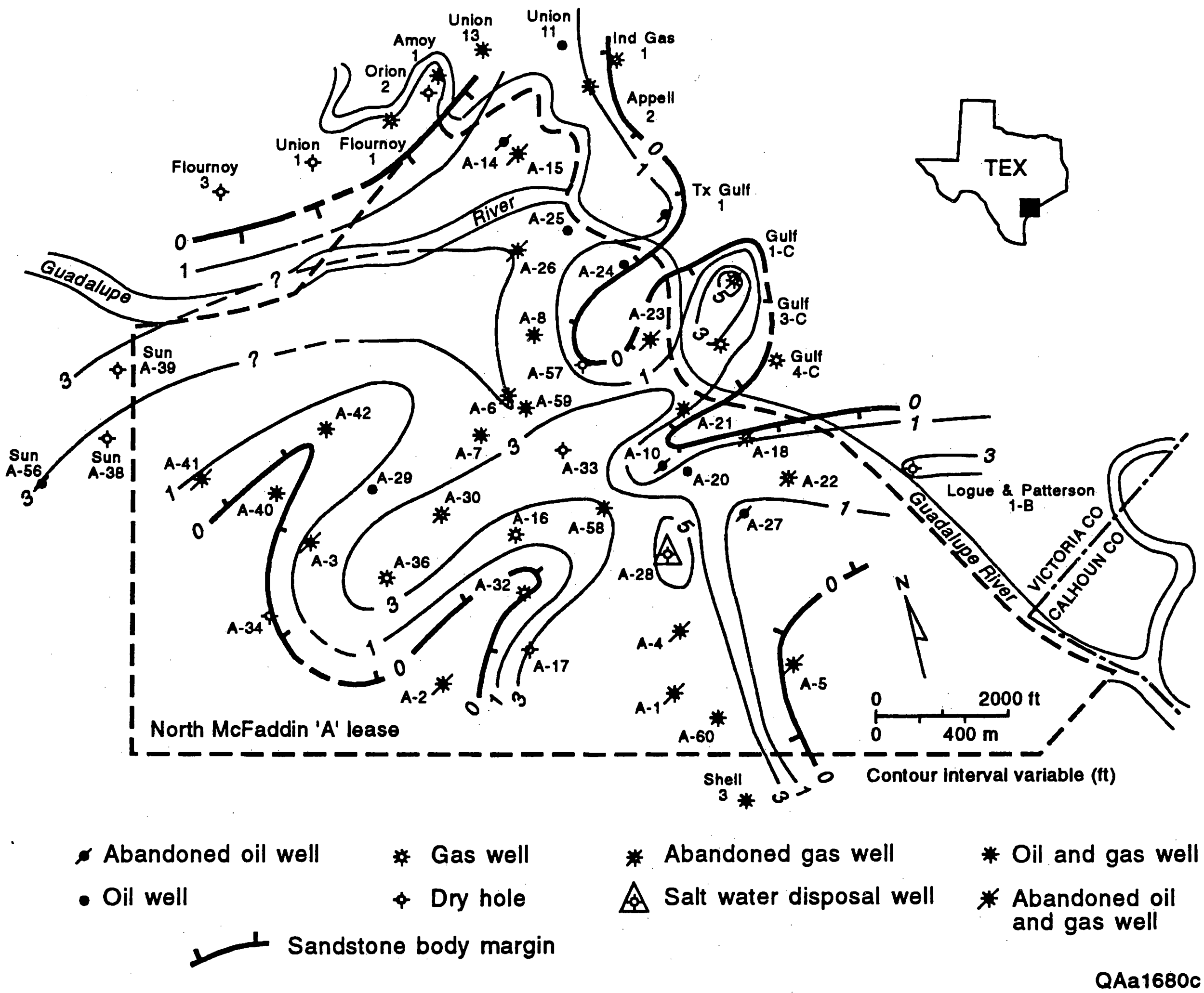


Figure 19. Net-thickness contour map of the 4,200-ft zone No. 5 reservoir. Units = ft.

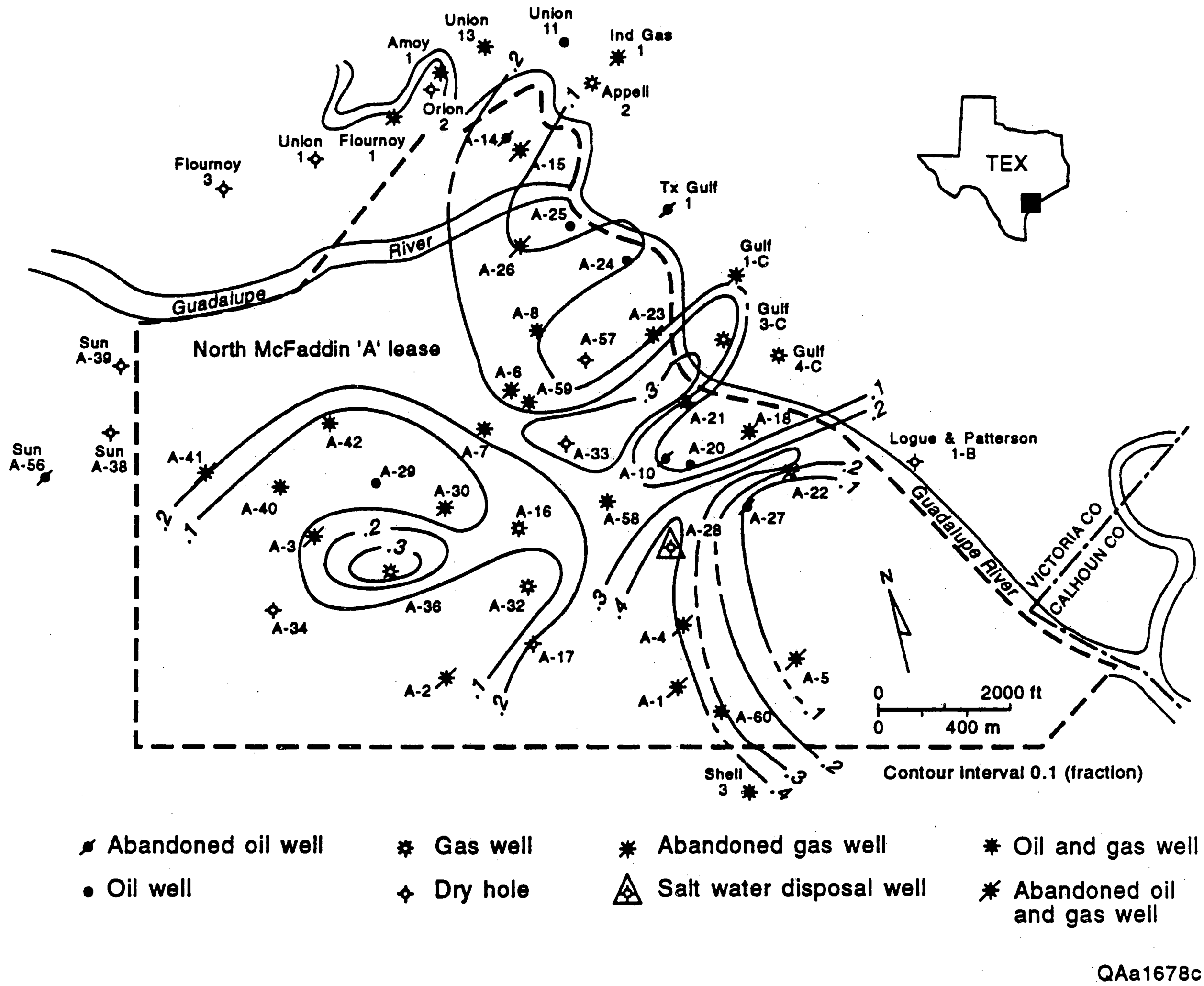


Figure 20. Relative spontaneous potential contour map of the 4,200 ft zone No. 5 reservoir. Units = fraction.

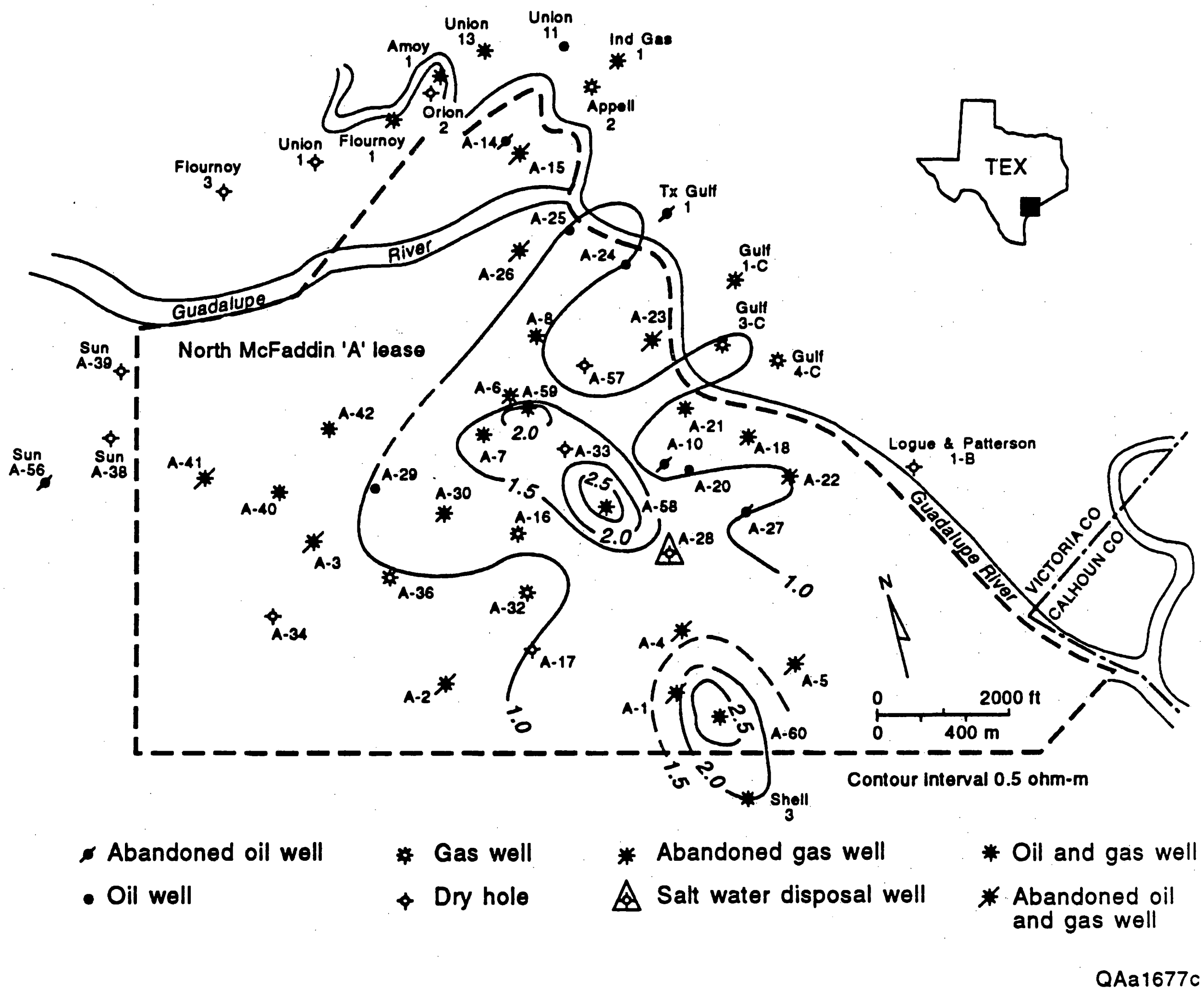


Figure 21. Deep-resistivity contour map of the 4,200-ft zone No. 5 reservoir. Units = ohm-m.

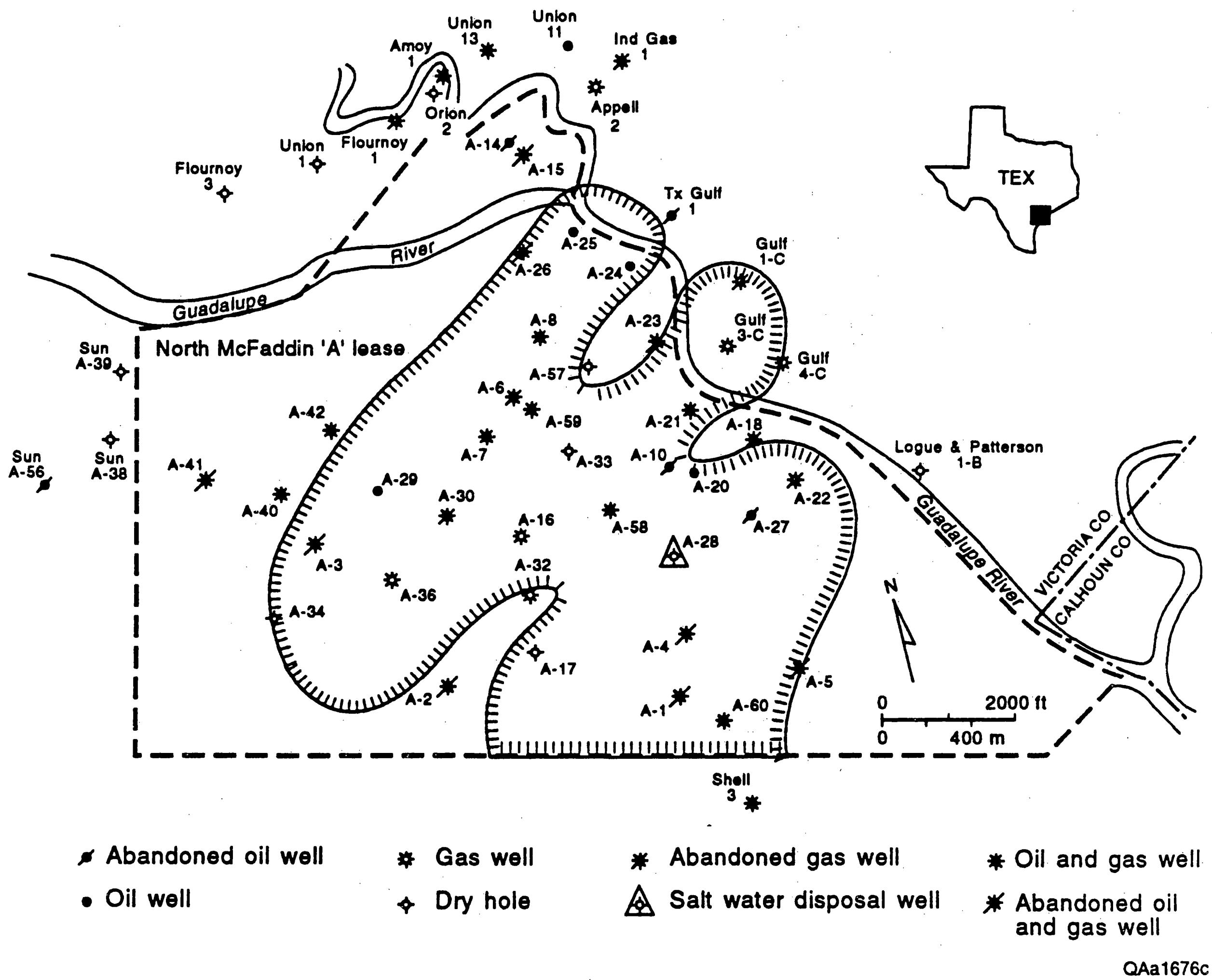


Figure 22. Potentially productive limits of the 4,200-ft zone No. 5 reservoir. Refer to table 1 for values of areal extent and average thickness.

the reservoir under the North McFaddin lease is 1,190 acres, with an average thickness of 2.4 ft. The volumetric estimate for original gas in place was approximately 2,100 Mmcf.

A radial-flow simulator was used to estimate the productivity and potential drainage volume of the A-58 well on the basis of daily records of flow rate and wellhead pressure. The drainage volume and effective permeability in the reservoir model were varied to history-match the declining trend of the first 6 mo of production (April through October 1992). A reservoir model with an initial gas in place of 1,000 Mmcf and a permeability of 13 md closely matches the performance of the well. The simulation exercise assumed that there was no formation damage or stimulation. The area of the reservoir model was 545 acres, with a net thickness of 2.4 ft. The simulation exercise also assumed that pressure depletion is the only drive mechanism and that a minimum volume of contacted gas was needed to match the performance of the well.

A wireline pressure test of the correlative reservoir in well A-60 recorded 1,786 psi in December 1992, indicating that the original gas in place volumetric estimate (2,100 Mmcf) for this reservoir is reasonable. Petrophysical evaluation indicates that the reservoir in well A-60 is potentially gas productive. At the time that the wireline pressure test was performed in well A-60, the A-58 well was estimated as producing 120 Mmcf. Within the mapped potentially productive limit of this reservoir (1,190 acres), calculations of expected pressure decline resulting from a production of 120 Mmcf predict an average reservoir pressure of approximately 1,700 psi, 120 psi less than original reservoir pressure. Because the recorded pressure (1,786 psi) is higher than the expected pressure (1,700 psi), either the volumetrically estimated figure of original gas in place (~2,100 Mmcf) is pessimistic (assuming pressure depletion as the sole producing mechanism and uninterrupted reservoir permeability architecture between wells A-58 and A-60), or the increase in expected reservoir pressure recorded in well A-60 is the result of reservoir compartmentalization. Deterioration of the SP/SSP well-log parameter between wells A-58 and A-60 supports the latter hypothesis. A shut-in pressure-buildup test in well A-58 would help confirm drainage estimates.

The productivity of well A-58 indicates a recovery of 80 percent of contacted original gas in place with a flowing bottomhole pressure of 200 psi and an abandonment static pressure of 400 psi.

Abandonment conditions were estimated with a radial-flow simulator using a final economic rate of 50 mcf/d. The recovery of 80 percent of the original gas in place (2,100 Mmcf) would yield 1,680 Mmcf. Assuming exponential production decline rates, from 750 to 50 mcf/d, the length of time required to recover 1,680 Mmcf would be approximately 18 yr. The recovery of remaining reserves could be accelerated by the completion of this reservoir in the A-59 and A-60 wells, where log evaluation indicates potential economic gas production. In addition to the recommended recompletions in A-59 and A-60, the contoured well-log parameter maps also delineate an area of interest midway between A-4 and A-17.

4,800-Ft Zone (No. 2 Reservoir)—Bypassed

This potential gas reservoir, relatively thick compared to other thin-bed units investigated during the study, may contain a significantly large bypassed resource (figs. 23 through 27). The potentially productive areal extent of this reservoir was calculated at 740 acres, with an average thickness of 10.5 ft. Original gas in place was estimated at 5,404 Mmcf and risked reserves at 1.4 Bcf (table 3).

A wireline pressure test of 1,971 psi, recorded in December 1992 from the correlative zone at a depth of 4,868 to 4,864 ft in well A-60, indicates original reservoir pressure. Formation evaluation predicts a reservoir of low permeability, characterized by gas and minor water production. A completion in well A-60 should be attempted.

Evaluation of operator files indicated a prior completion in this reservoir in well A-29 was initially gas productive but ultimately failed. The current operator, Anaqua Oil and Gas, indicated that this may have been a mechanical failure resulting from completion problems in the A-29 well.

Superimposed well-log parameter maps indicate that wells A-59 and A-24 offer the best opportunities for completion in this zone. Sidewall core data from this zone in well A-24 indicate potential gas production, supporting this recommendation. Contingent upon completion results would be the recommendation that the zone be additionally completed in well A-29. This

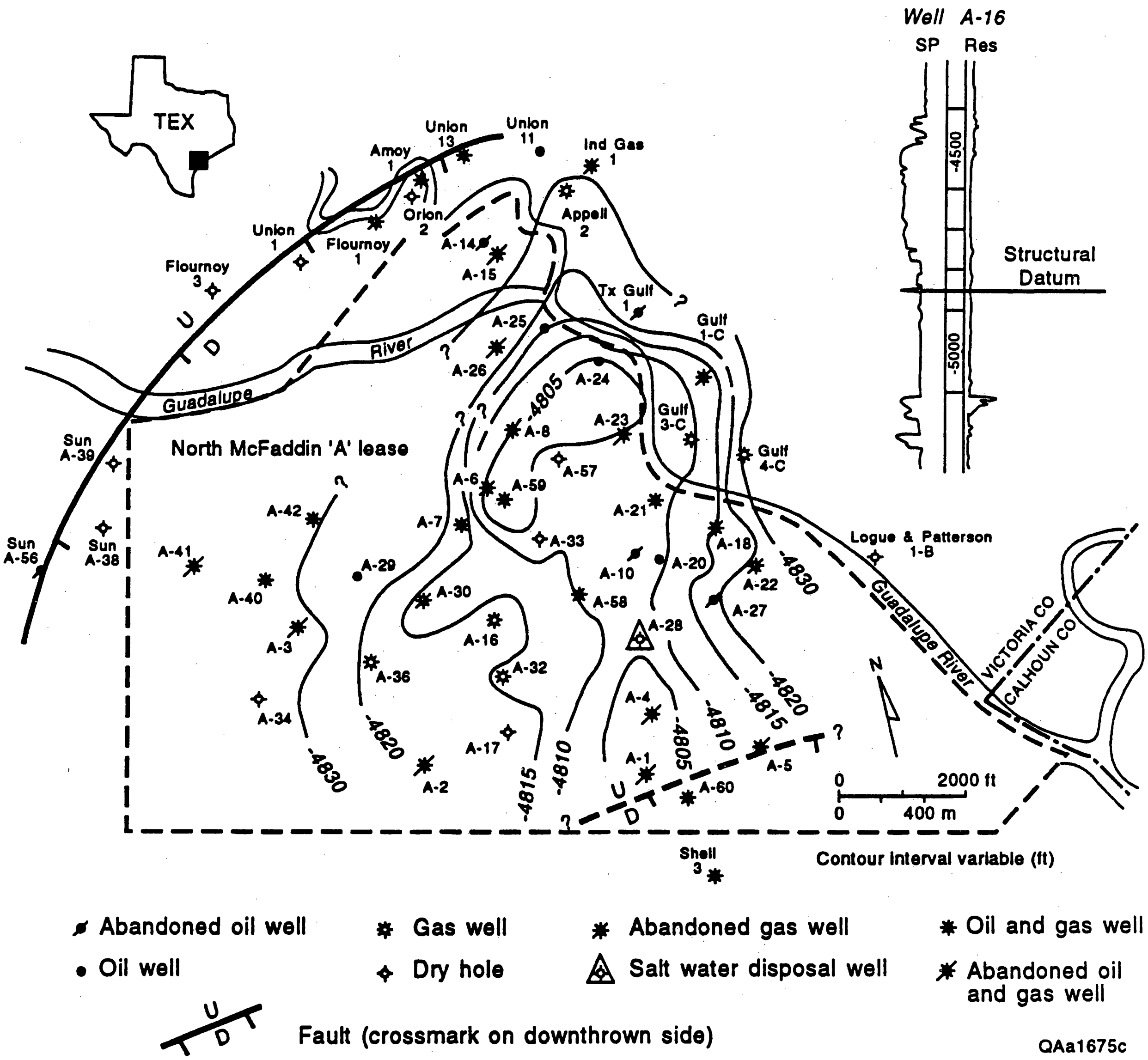


Figure 23. Structure-contour map for the 4,800 ft zone. Depths relative to sea level in feet. Note prominent northeast-southwest-trending fault northwest of the field, and the north-south trending linear-elongate pericline that characterizes the center of North McFaddin field.

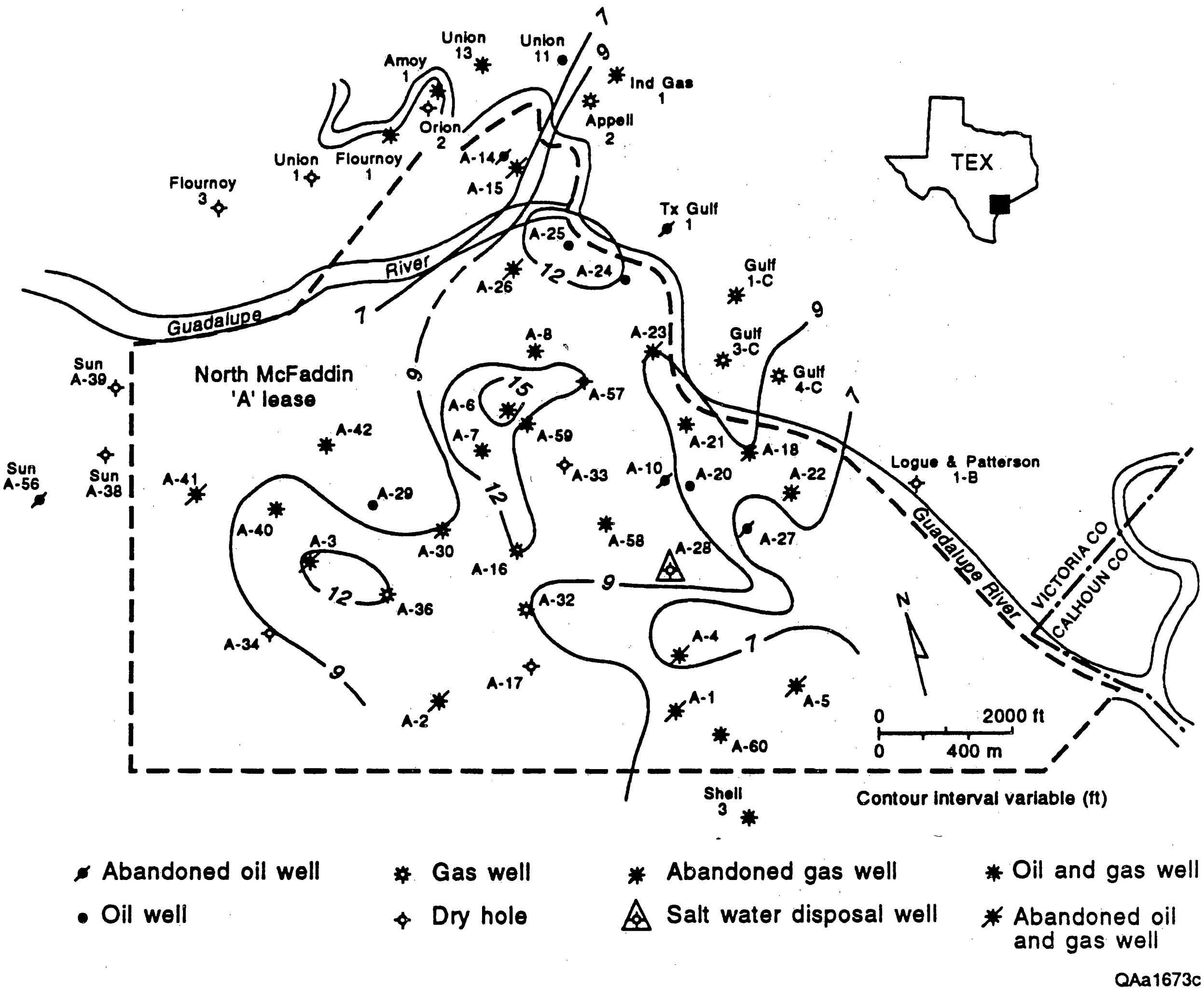


Figure 24. Net-thickness contour map of the 4,800 ft zone No. 2 reservoir. Units = ft.

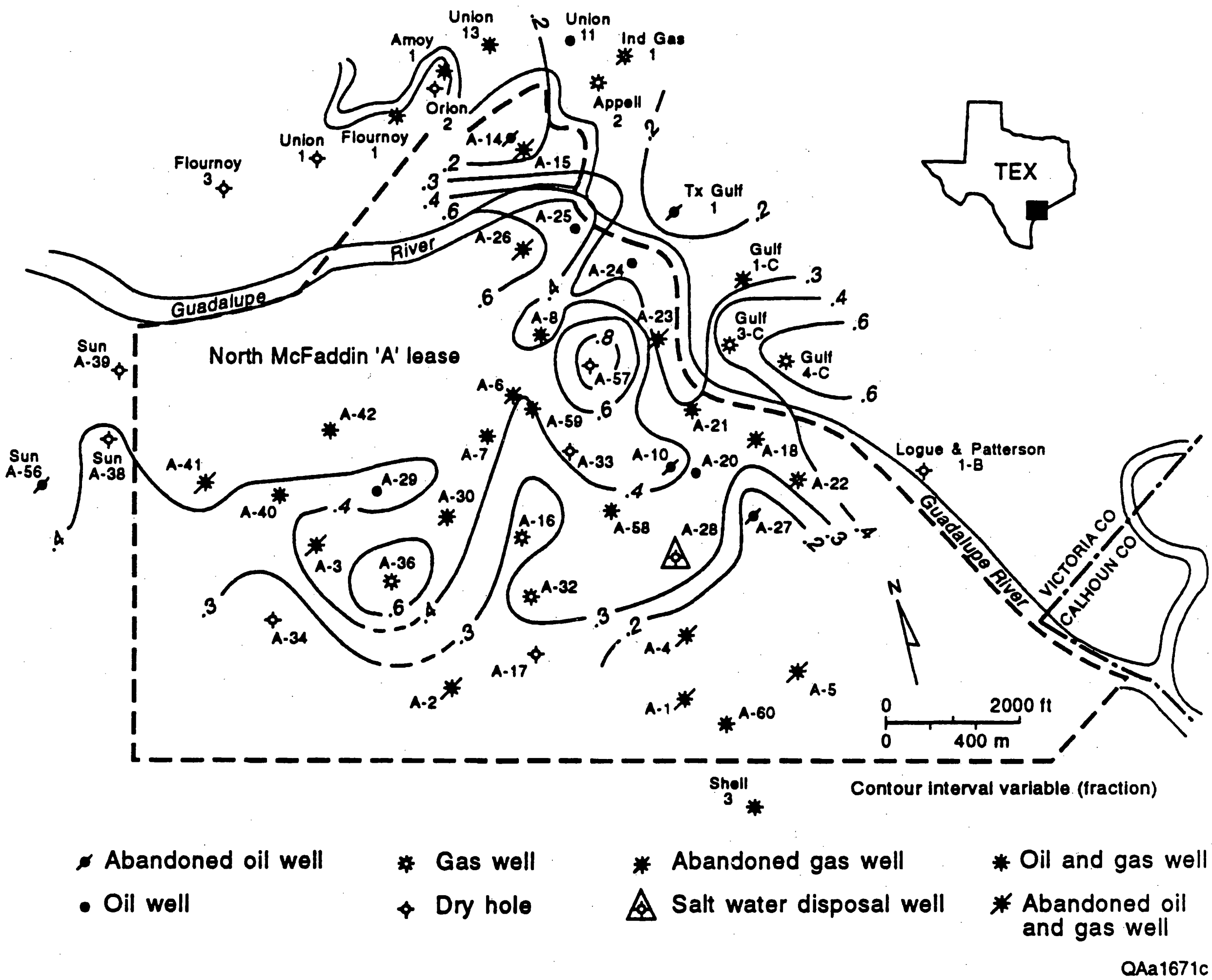


Figure 25. Relative spontaneous potential contour map of the 4,800-ft zone No. 2 reservoir. Units = fraction.

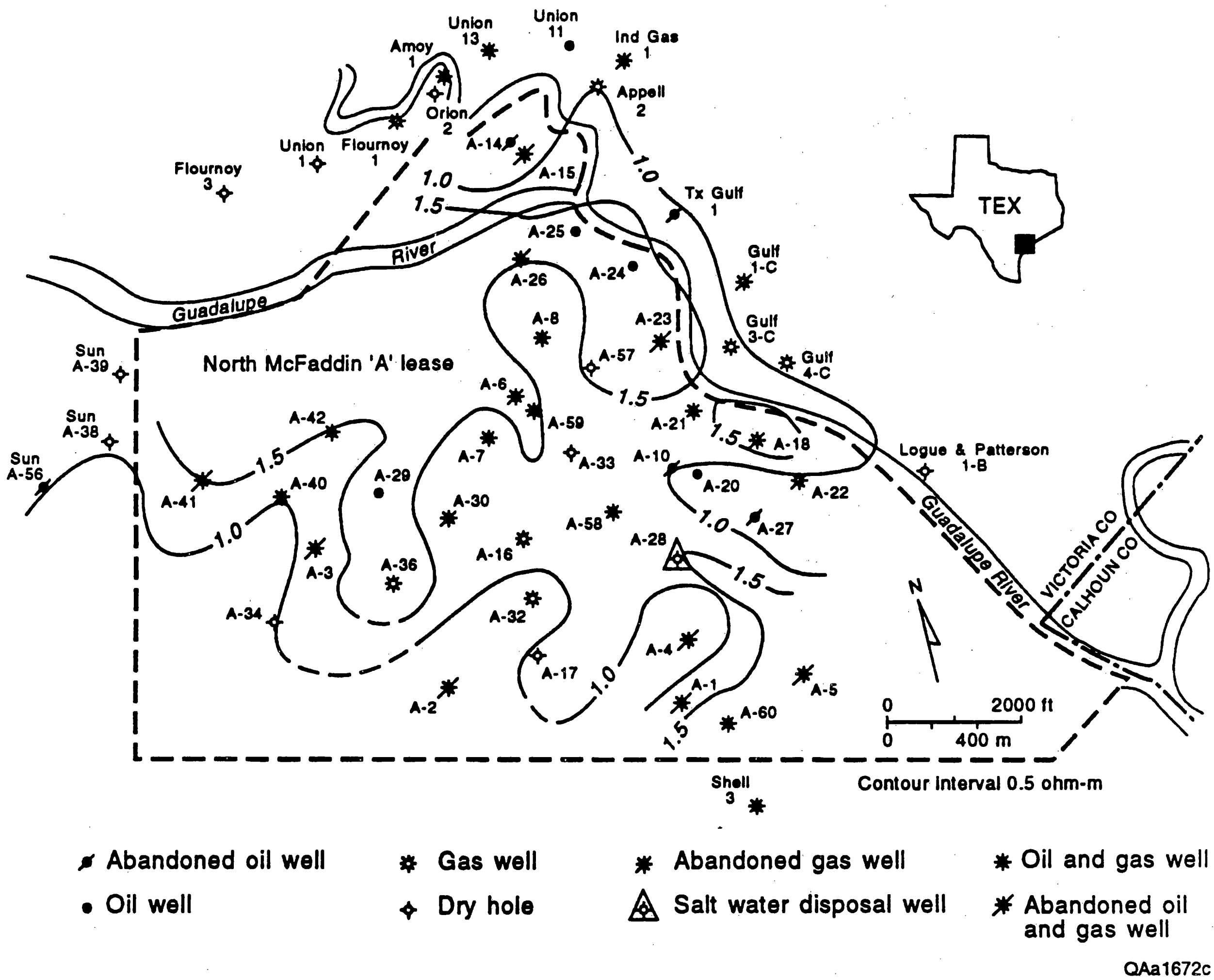


Figure 26. Deep-resistivity contour map of the 4,800-ft zone No. 2 reservoir. Units = ohm-m.

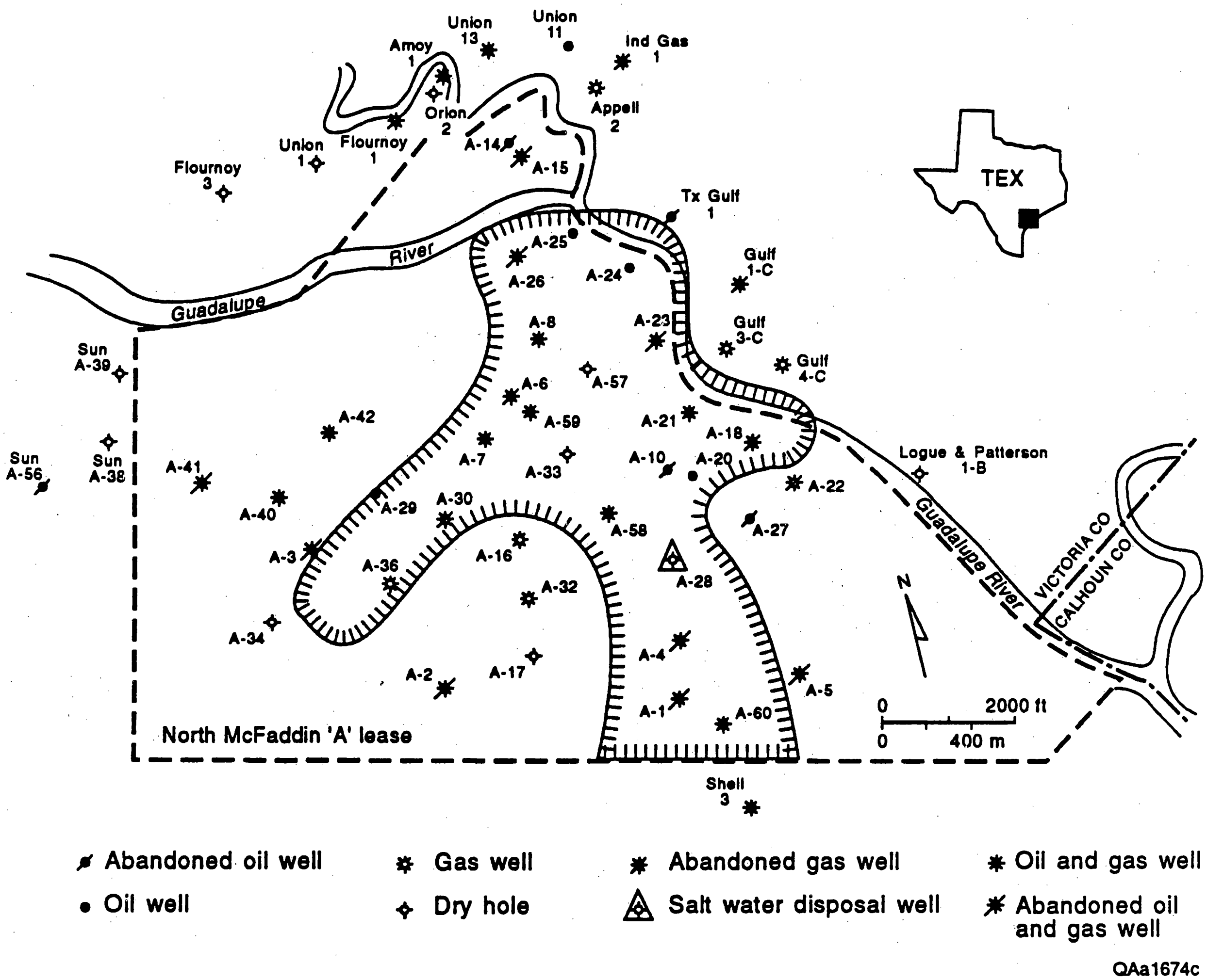


Figure 27. Potentially productive limits of the 4,800-ft zone No. 2 reservoir.

completion is recommended on the basis of a previous production attempt and an optimistic superposition of well-log parameters.

MINI-EVALUATION CASE STUDY II—AGUA DULCE FIELD

by R. A. Levey, W. A. Ambrose, M. A. Sippel, J. M. Vidal, and J. R. Ballard

Location of Study Area

The study area under investigation is the 490-acre H. W. Gee lease (hereafter referred to as the Gee lease) in the western part of Agua Dulce field in the I.&G.N.R.R. A-174 survey. It is approximately 4 mi southeast of the town of Agua Dulce, which is approximately 35 mi west of Corpus Christi, and it lies within Nueces County, southeast Texas (fig. 3).

Structural and Stratigraphic Framework

Agua Dulce field lies within the Rio Grande Embayment structural province (fig. 3). The Rio Grande Embayment is one of several entry points for major river systems draining the ancestral Gulf of Mexico. The Oligocene Frio Formation is a sediment-supply-dominated depositional sequence characterized by rapid deposition and high subsidence rates (Galloway and others, 1982; Morton and Galloway, 1991). Thickness of the Frio Formation varies from less than 2,000 ft near the Vicksburg Flexure to greater than 9,000 ft downdip toward the central part of the embayment. The structural style in the Rio Grande Embayment is characterized by discontinuous belts of strike parallel to growth faults and deep shale ridges and massifs. Underlying salt is thin or absent (Galloway and others, 1982).

Gas reservoirs in Agua Dulce field are located in the Fluvial/Deltaic Sandstone gas play along the Vicksburg Fault Zone (FR-4), one of the 10 Frio gas plays in Texas (Kosters and others, 1989). The dominant trapping mechanism for reservoirs in this gas play is controlled by a combination of structural and stratigraphic factors, with faulted anticlinal closure, facies change, and reservoir pinch-outs (Kosters and others, 1989). Most of the gas production in the FR-4 play is from middle Frio reservoirs. A combination of the depositional effects on reservoir facies and the proximity of the Gee lease to the major Vicksburg growth fault has resulted in abundant fault block trap and stratigraphic pinch-out opportunities on the downthrown (basinward) side of the flexure zone (fig. 3).

The Frio Formation is one of the major progradational offlapping stratigraphic units in the northwest Gulf of Mexico basin (fig. 1). Middle Frio reservoirs in Agua Dulce field are part of the Guedyan fluvial system (fig. 4), updip from the Norias delta system (Galloway and others, 1982). Middle Frio strata consist of fluvial depositional systems that contain channel-fill and associated crevasse-splay reservoir facies. Criteria for identifying these channel-fill and splay deposits from well logs and core were described by Jirik (1990), Kerr and Jirik (1990), and Kerr (1990). Agua Dulce field is at the northern limit of the FR-4 gas play. Several giant gas fields, including Stratton and Seeligson fields, are part of this play. Initial geologic analysis of these middle Frio reservoirs in Agua Dulce field reported these composite channel-fill deposits were as much as 30 ft thick and 2,500 ft wide and probably occur in rather long linear belts (Kerr and Jirik, 1990). Interpretation of 3-D reflection seismic data, acquired from the middle Frio in Seeligson field, 35 mi south along the trend of the FR-4 gas play, indicates that individual channel systems may be only 1,000 ft in width (Ambrose and others, 1992). Splay deposits in the middle Frio are up to 20 ft thick and are proximal to channel systems (Kerr, 1990). Porosities in these fluvial reservoirs range from 15 to 25 percent, with permeabilities of less than 1 to greater than 4,000 md.

The local structure in the Gee lease is largely influenced by the rollover structure and faulting associated with the Vicksburg flexure to the northwest. The shallowest reservoirs in the field are influenced by the low-relief anticlinal structure (fig. 28). Form-line analysis of dip-oriented 2-D reflection seismic lines across the study area demonstrates the structural orientation of the Frio Formation and Vicksburg Group (fig. 29). Reprocessing of 2-D reflection seismic lines acquired in the 1980's revealed that the study area is influenced by three stages of structural development: (1) a major down-to-the-basin fault in the Vicksburg fault zone, which is the earliest structural influence, (2) a counterregional antithetic fault system, which has a down-to-the-west orientation, and (3) a closely spaced synthetic fault system (few thousands of feet apart), which probably represents

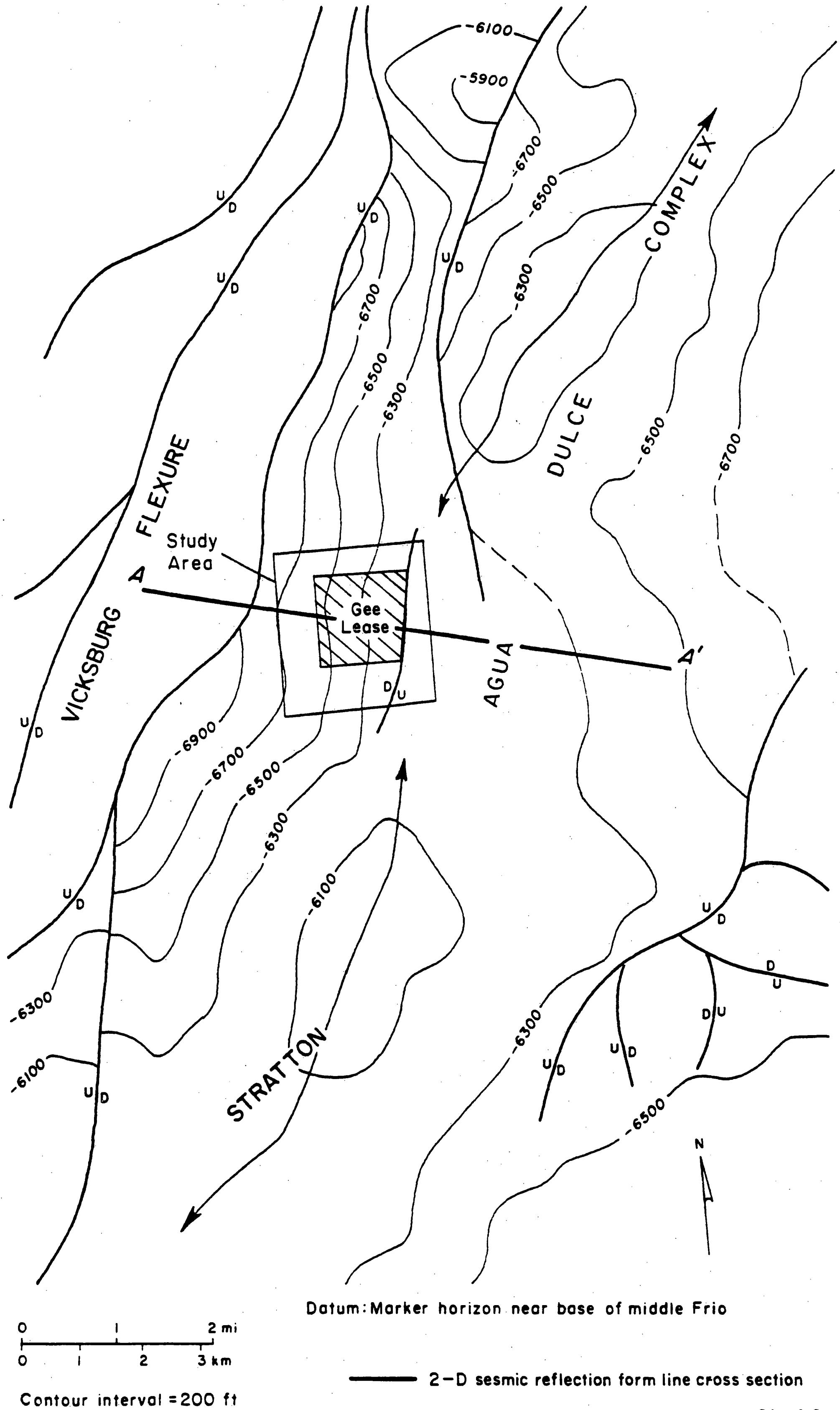


Figure 28. Location of the Gee lease in the case II study area. Structure top of a marker horizon near the base of the middle Frio. Location of cross section in figure 29 is indicated.

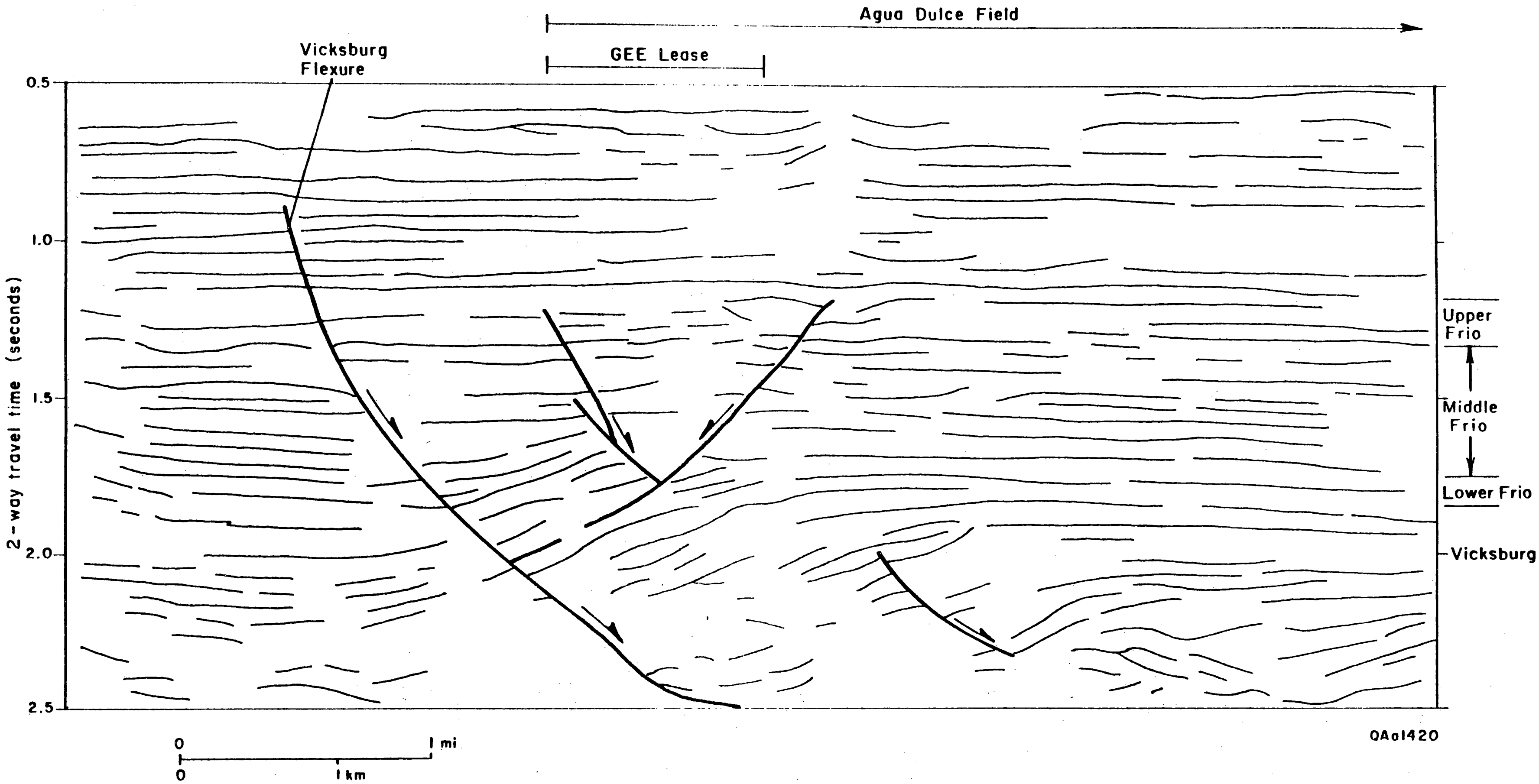


Figure 29. Dip-oriented form line cross section from 2-D reflection seismic log showing the location of the study area in Agua Dulce field and major faults associated with the Vicksburg flexure.

accommodation to the antithetic fault system and is characterized by minor displacement with down-to-the-basin orientation. Structural overprint on the Gee lease is more significant than in previous SGR research study areas in Stratton and Seeligson fields, which are also in the FR-4 gas play.

Production and Development History

Agua Dulce field, a mature giant gas field, has produced more than 1.6 Tcf of natural gas since its discovery in 1922. Agua Dulce field is the earliest in the second phase of giant hydrocarbon fields discovered in the Gulf of Mexico Basin between 1928 and 1941 (Nehring, 1991). The Agua Dulce Oil and Gas Company drilled many of the initial wells in the field. These wells were less than 3,000 ft deep and produced gas from relatively shallow Miocene sandstone reservoirs. Oil and gas production from the deeper Frio sandstone reservoirs began in the late 1920's and early 1930's; some of the earliest natural gas production from the Frio in southeast Texas was in these reservoirs. Initial development of reservoirs in the Frio Formation at Agua Dulce field occurred in the late 1930's and early 1940's. Gas production records before 1937 are not available. Agua Dulce field has at least 19 reservoirs (16 in the Frio and 3 in the Vicksburg) that have produced greater than 10 Bcf of natural gas. Five of these reservoirs (4 Frio, 1 Vicksburg) have cumulative production greater than 100 Bcf. Depths of these major reservoirs range from 4,620 to 13,728 ft. Most of the major Agua Dulce reservoirs (>10 Bcf cumulative production) are prorated and produce nonassociated gas.

A type log from Agua Dulce field illustrates the well log response and nomenclature of the reservoirs in the field (fig. 30). There are 36 potential reservoirs to a depth of 7,000 ft in or adjacent to the study area. Because of the early development of the Agua Dulce field, the exact history of operators in the field is difficult to trace. Agua Dulce Oil and Gas Company was one of the early operators in the late 1920's. Union Producing Company was the principal developer in the field. The Chicago Corporation (later Champlin) and Lockhart Oil and Gillring Oil companies were also active in developing the field from the 1930's through 1960's. The distribution of wells in the study

Union Producing Company
No. A-7 Clara Driscoll

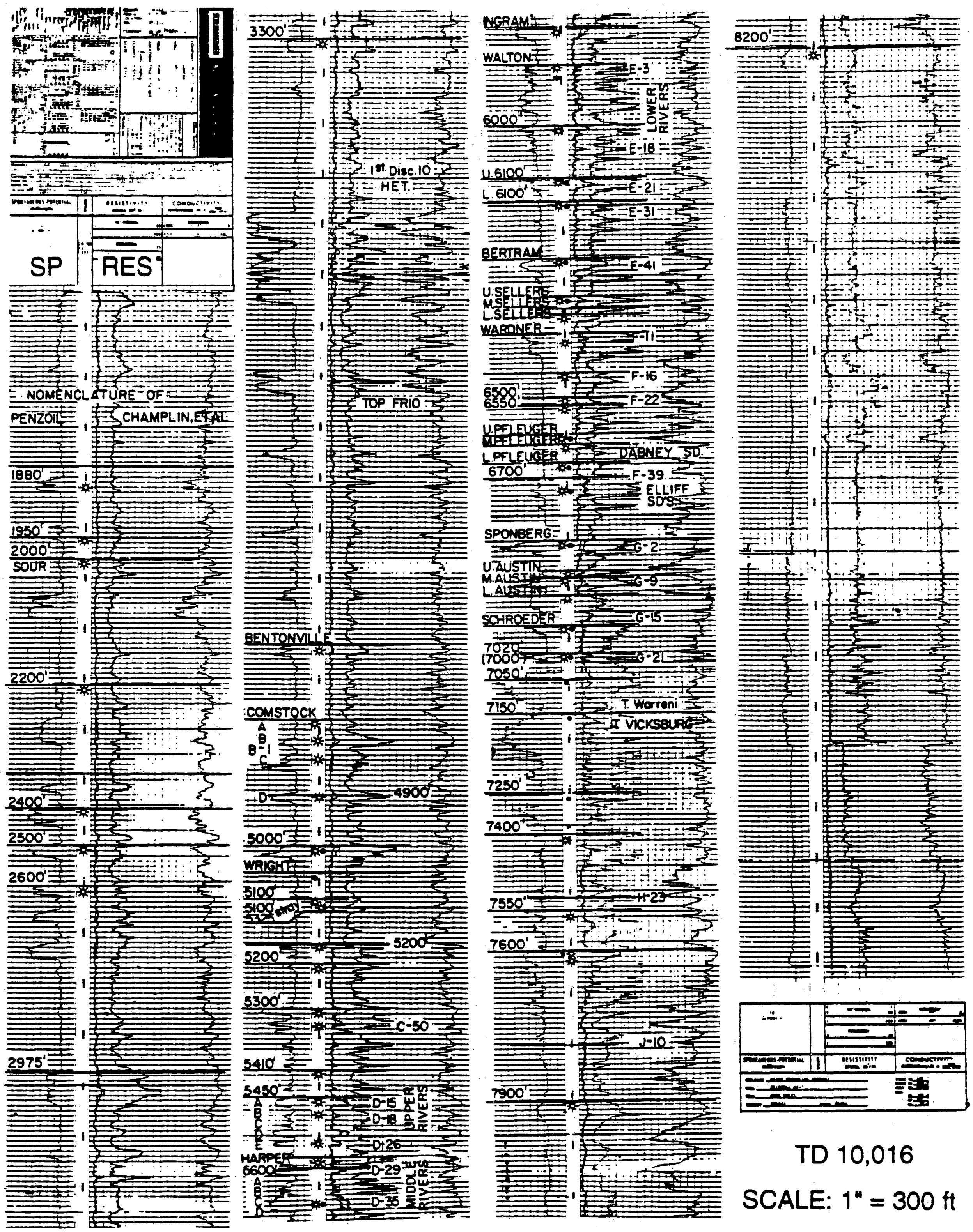


Figure 30. Type log from the Agua Dulce field showing the well log response and reservoir nomenclature used in the field.

area, including the approximately 490-acre Gee lease, along with a grid pattern that represents a 40-acre surface pattern, is illustrated in figure 31.

Ten wells have been drilled on the Gee lease. The Sanders Nos. 1 and 2 wells were drilled by the Agua Dulce Oil and Gas Company. Union Producing Company drilled the Gee Nos. 1, 2, and 3 wells (fig. 31). Pennzoil Producing Company, which acquired the Union Producing operations in the 1960's, drilled the Gee Nos. 4 and 5 wells. The Gee lease was then acquired for redevelopment in 1991 by Pintas Creek Oil Company, and Lou Little Operating Company drilled the Gee Nos. 6, 7, and 8 wells on behalf of Pintas Creek. Cumulative production records for 8 of the 10 wells were retrieved from the Dwight's Production data base. Cumulative gas production was 13.7 Bcf between the depths of 4,400 and 6,700 ft for five of these wells (appendix 4) prior to the renewed development by Pintas Creek Oil Company, which drilled three additional wells after July 1991. Most of the previous gas production (12.5 Bcf) in the Gee lease was from reservoirs that were not among the 10 reservoirs evaluated for secondary gas, or from wells on the east side of the synthetic fault that were separate from the targeted reservoirs in the Gee lease. As of 1992, six of the wells in the Gee lease are still active. Commercially available production records indicate that all Gee lease production has come from middle Frio reservoirs. The Bentonville reservoir, which is approximately 4,600 ft deep, has produced over 6 Bcf from Gee wells Nos. 1 and 2. This highly prolific reservoir, which is approximately 45 ft in total thickness, covers a large part of the study area. The Bentonville reservoir is ranked ninth out of the 16 most productive gas reservoirs in the field.

Resource Analysis

Incremental gas opportunities in the case II study area in Agua Dulce field are a function of geological complexity and applications of state-of-the-art technology. Geological complexity at Agua Dulce field is controlled by a combination of sandstone reservoir geometry and a function of the reservoir genesis associated with fluvial depositional systems, diagenesis, and faults. The primary reservoir facies in the middle Frio are discontinuous sandstones composed of channel-fill and splay

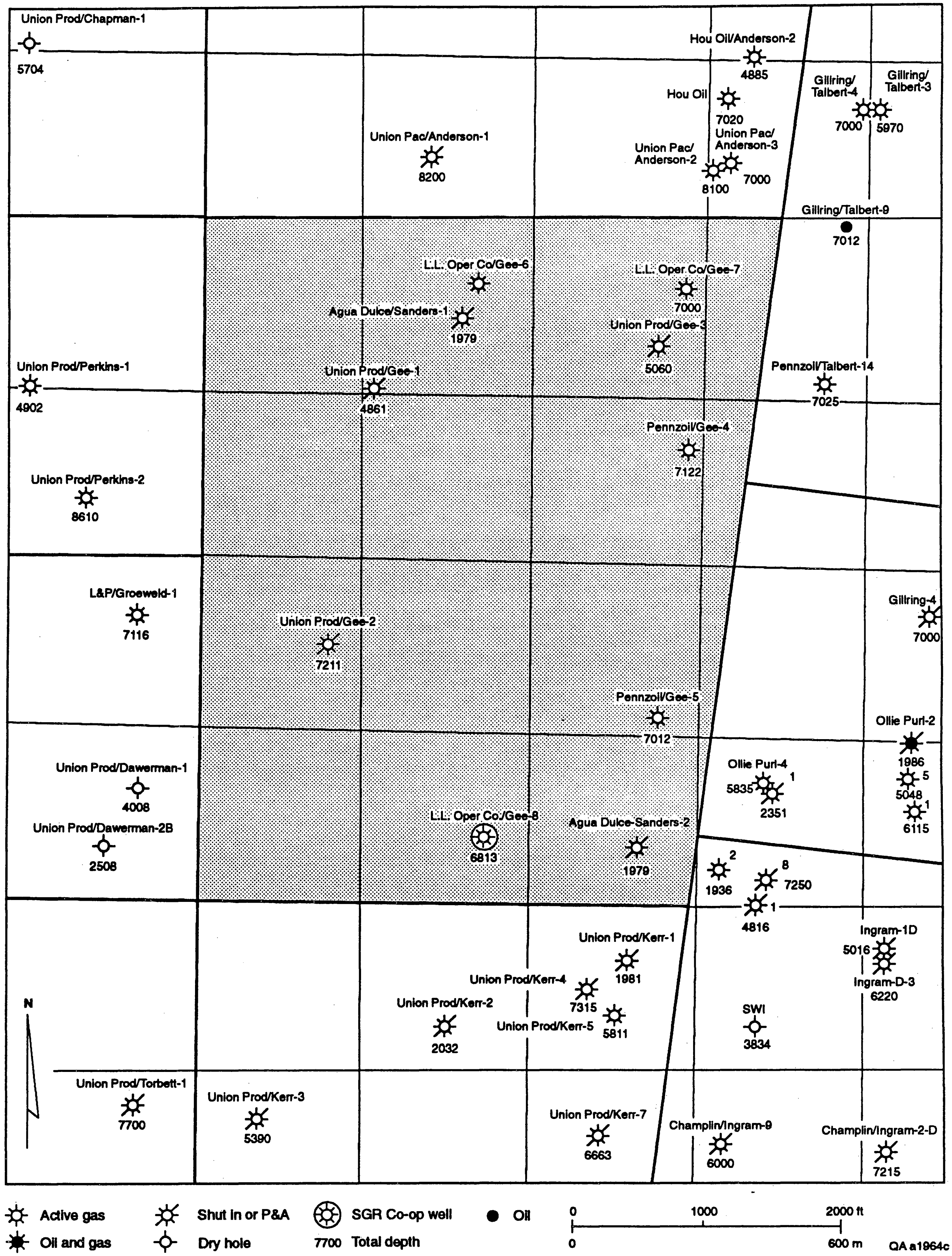


Figure 31. Map of the study area showing the distribution of wells in the study area, including the approximately 490-acre Gee lease, along with a grid pattern that represents a 40-acre surface pattern.

deposits that vary in thickness (primary depositional attribute) and reservoir quality (secondary diagenesis). The proximity of the study area to the Vicksburg flexure has superimposed a structural fabric on the primary depositional heterogeneity of the reservoir and any diagenetic effects on reservoir quality. Recognition of the reservoir depositional environment affecting reservoir genesis is crucial to the SGR approach. An understanding of reservoir genesis is important for predicting interwell reservoir trends and for determining the potential magnitude of the resource. Incremental opportunities also result from the technological advances in application of integrated well log analysis and formation evaluation. In one example, the comparison of critical water saturation determinations from sidewall cores, the screened wireline pressure tests, and the density-neutron crossover signature on open-hole logs are integrated for evaluations to identify reservoir intervals for testing. Combining the formation evaluation and geological and engineering production data in a systematic approach is the means to develop this type of secondary resource.

Ten wells were drilled from 1938 to 1992 in the 490-acre Gee lease. Twenty other wells within 1,000 ft of the periphery of the Gee lease boundary (fig. 31) were considered part of the study area in order to extend control beyond the Gee lease and to improve the extrapolation in net-sandstone-thickness trends for each producing or potential reservoir.

The experience of Pintas Creek Oil Company demonstrates that untapped, bypassed, and incompletely drained gas reserves remain under the Gee lease. Permeabilities of the sandstones containing these resources were determined from pressure-buildup tests to be in the range of 1 to 100 md. The buildup tests also indicated multiple near-well barriers in each of the wells tested. Completions made by Pintas Creek Oil in the Middle Frio reservoirs indicated several problems with the recovery of the remaining resource. The primary problem results from a strong structural overprint. (Pressure-buildup tests indicated narrow drainage shapes.) Structural interpretation of the reservoirs indicated multiple faults crossing the lease in a southwest to northeast direction. The faulting appeared to be more severe with increasing depth. These faults are normal to the depositional trends of the Middle Frio sandstones and create a situation where the potential reservoir compartments are small. There are also several reservoirs at depths from 5,400 to 5,700 ft, which indicates untapped and incompletely drained resources. However, these sandstones contain significant amounts of volcanic ash, which has created a diagenetic problem. Reservoir permeability in these sandstones is reduced, and stimulation by hydraulic fracturing is often required for commercial production.

In the case II study, identification of the SGR resource consisted of four tasks that integrate geology, petrophysics, and engineering. Following a discussion of the tasks used to identify the resource, three reservoir examples are presented to demonstrate the methodology of evaluating all potential SGR reservoirs. Finally, gas-rate projections based on infield drilling and completions are used to evaluate the economics of recovering these resources after applying the methodology and technology.

Tasks for Identifying the SGR Resource

Task 1: Geological Evaluation. Detailed structural cross sections were constructed across the study area to determine the existence, location, and trends of faults (figs. 32 and 33). The cross sections were constructed from 1-inch electric logs, and each previously established or potential reservoir unit was correlated. The network of cross sections provided a basis for identifying which reservoir zone was correlative to previously existing or to new productive units as additional wells were drilled.

Task 2: Formation Evaluation. Computed log analysis of water saturations and bulk volume of water were used together with available sidewall core analysis results, wireline formation pressures, fluid sample analysis, and available well-test results, to screen for reservoirs that are gas productive in the modern logs of the Lou Little Nos. 6, 7, and 8 wells (fig. 34a, b, and c). In addition, all previous gas-productive intervals were correlated into the structural cross sections (figs. 32 and 33). The computation of porosity, water saturation, and pay sand thickness, in combination with

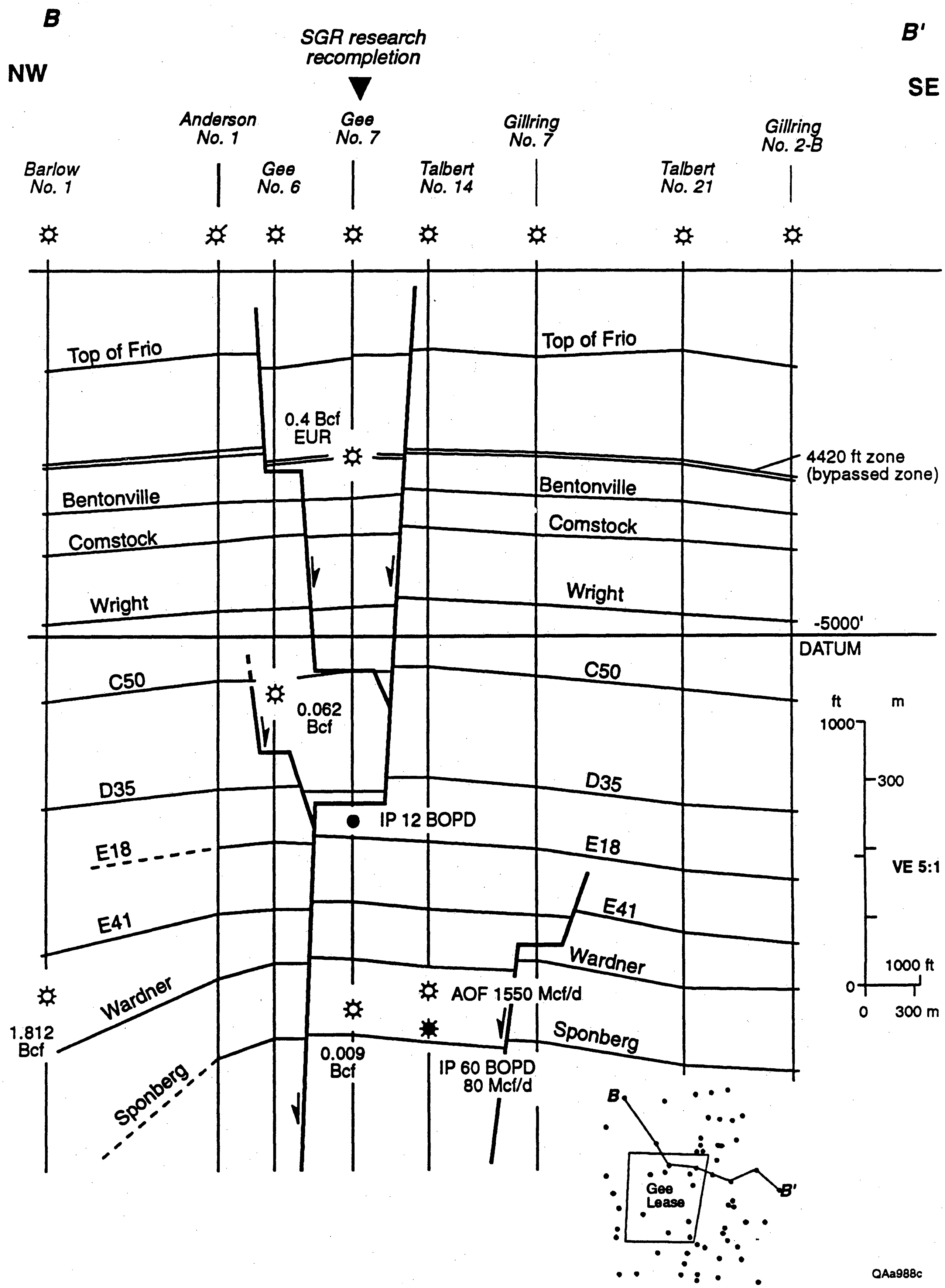


Figure 32. Structure cross section B–B'.

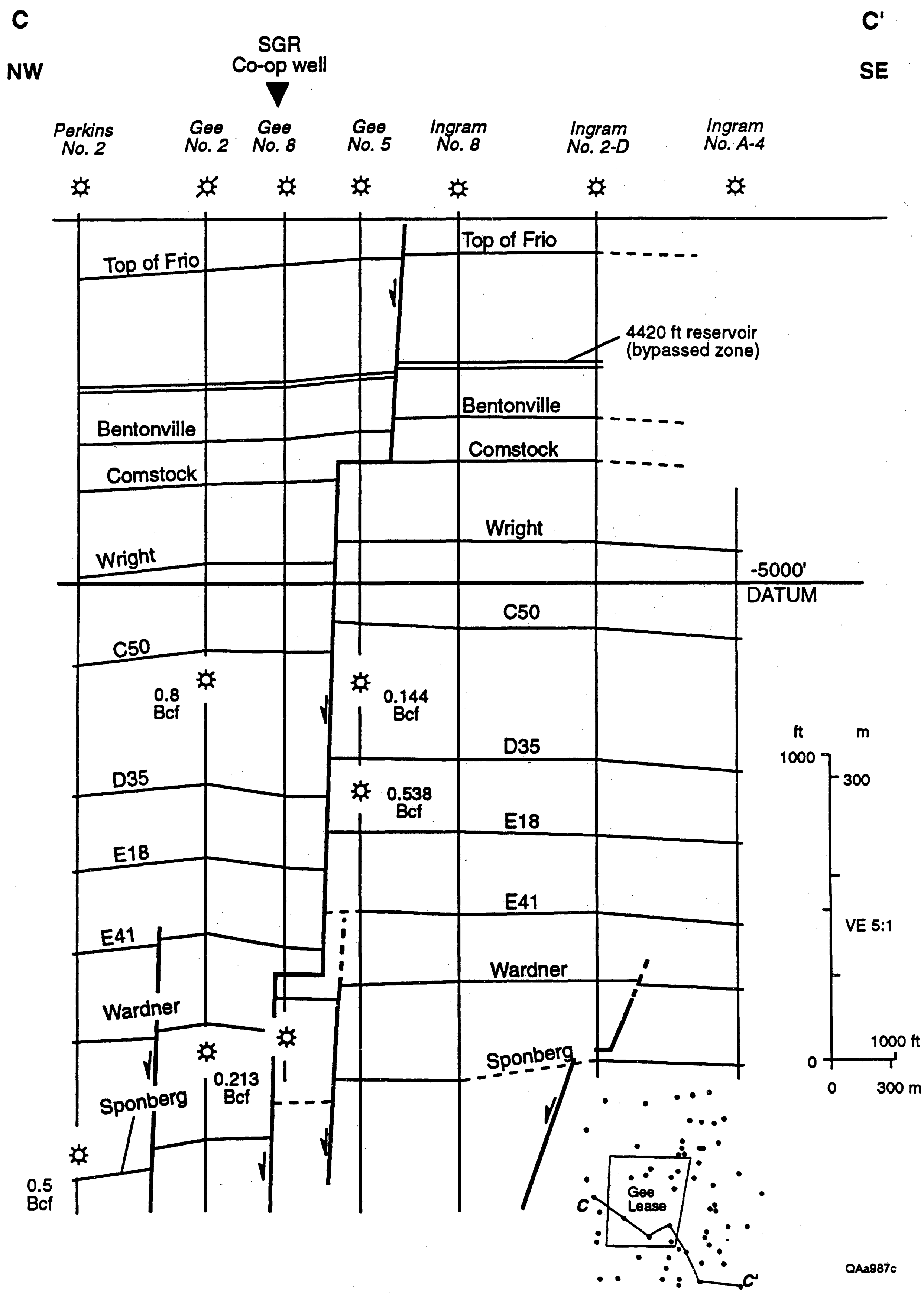


Figure 33. Structure cross section C–C′.

(a)

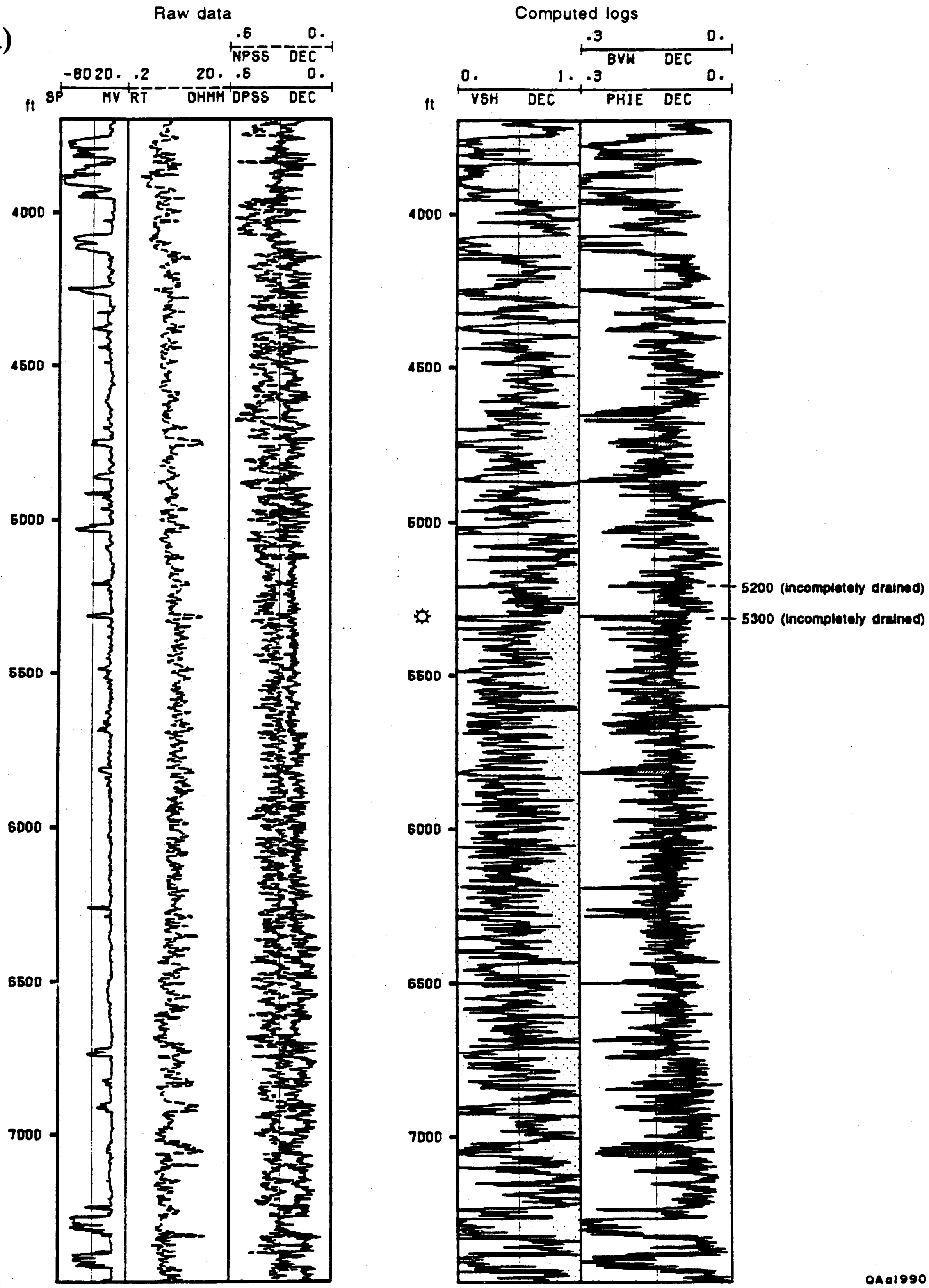
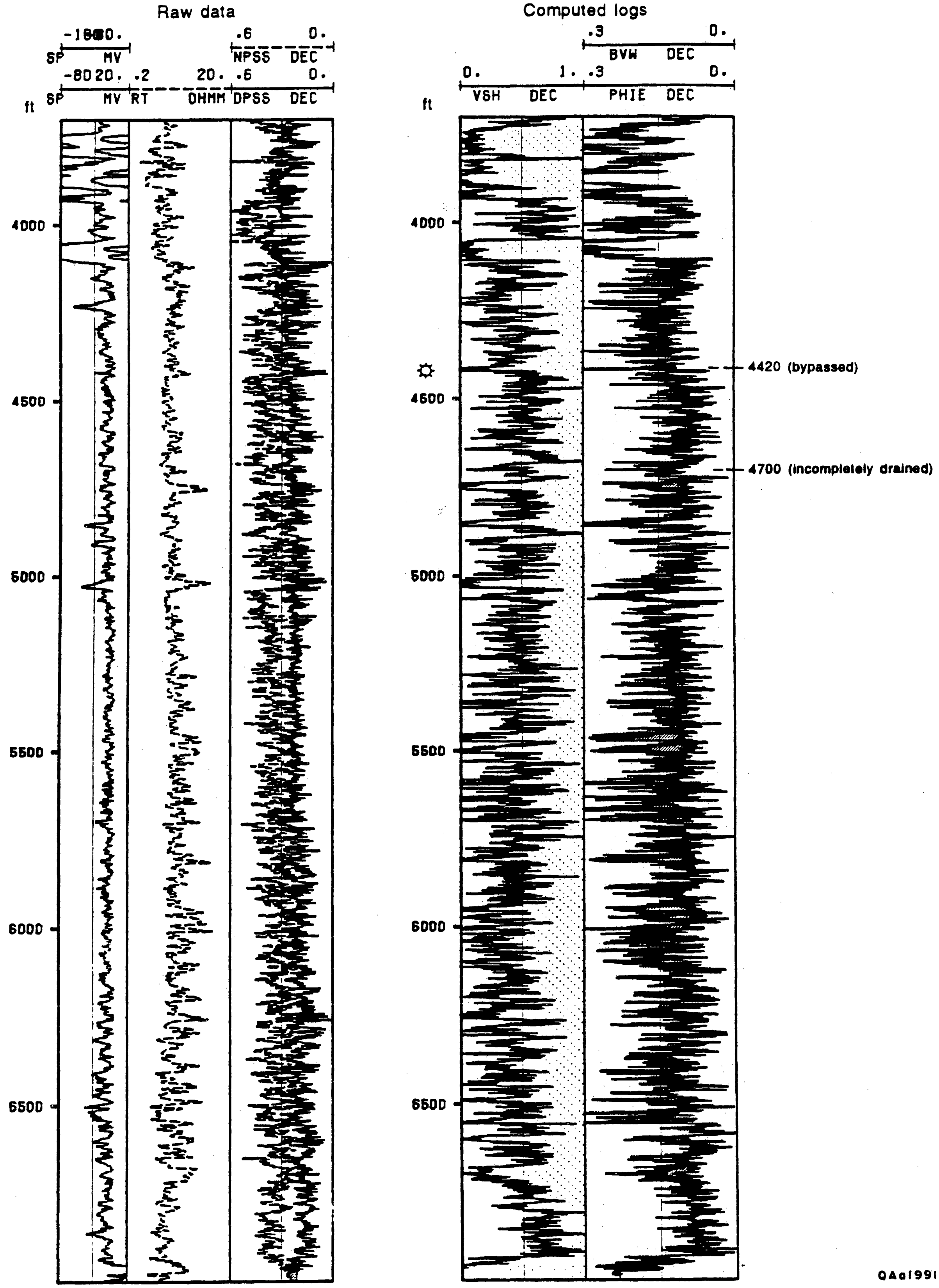


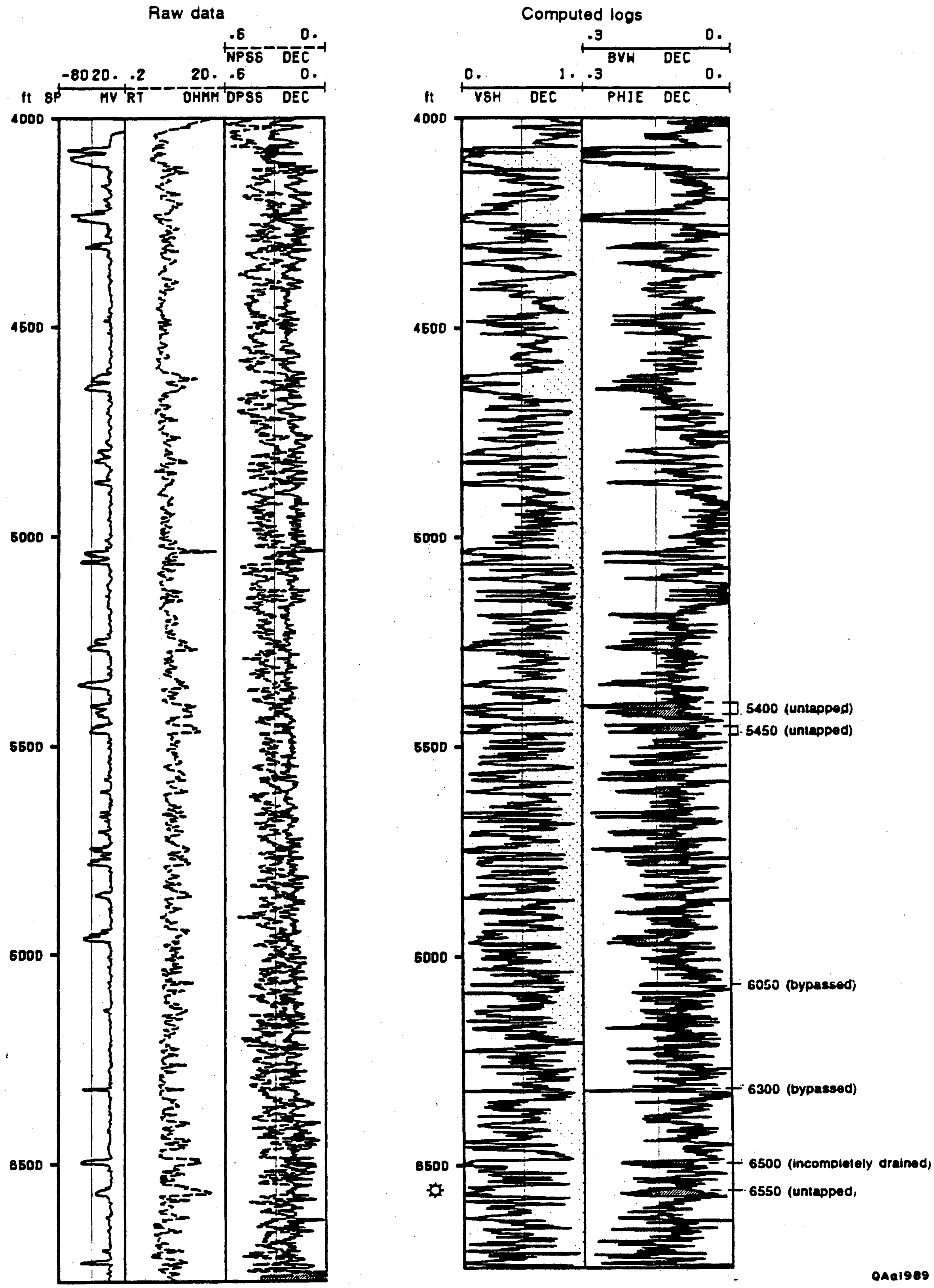
Figure 34. Log suite of SP, resistivity, compensated density neutron, and computed logs showing volume of shale, porosity, and bulk volume water for (a) Gee No. 6 well, (b) Gee No. 7 well, and (c) Gee No. 8 well.

(b)



Raw data
SP MV
SP MV
RT OHMM
NPSS DEC
DPSS DEC
ft
4000
4500
5000
5500
6000
6500
Computed logs
BVW DEC
VSH DEC
PHIE DEC
4420 (bypassed)
4700 (incompletely drained)
QAa1991

(c)



Raw data
Computed logs
ft
SP
-80 20.
MV
.2
RT
20.
OHMM
.6
DPSS
DEC
0.
NPSS
BVW
PHIE
VSH
1.
.3
4000
4500
5000
5500
6000
6500
5400 (untapped)
5450 (untapped)
6050 (bypassed)
6300 (bypassed)
6500 (incompletely drained)
6550 (untapped)
QAa1989

pressure and areal distribution, provides the parameters necessary for the reservoir engineer to calculate initial gas in place.

Task 3: Engineering Evaluation. Volumetric methods, supplemented by available pressure data and material-balance methods, were used to estimate the potential original gas in place for each of the reservoirs. These estimates allowed the ranking of the reservoirs by relative volume and potential for remaining development. The productive area and limits of each sand were delineated using maps of the structure and thickness. Reservoir pore volume was determined from the average thickness of each sand, the potentially productive area, and the average porosity and water saturation values (which were determined from the available modern logs). A net/gross thickness factor of 50 percent was applied to the average thickness. The net/gross factor was determined from log evaluations. In reservoirs with prior production, pressure data from wireline formation tests and pressure-buildup tests were utilized for material-balance calculation of original gas in place and comparison to volumetric resource estimates.

Task 4: Integration of Geology, Formation Evaluation, and Engineering Evaluation. Ten separate intervals were found to have secondary gas recovery potential. Table 4 lists the intervals for each of the three wells evaluated. Each reservoir was classified according to the appropriate SGR reservoir terminology category (fig. 5). Of the 10 reservoirs identified as containing incremental gas resources, 3 were classified as bypassed, 4 as incompletely drained, and 3 as untapped compartments (fig. 5).

Geologic analysis of structure cross sections and well log correlation indicate that the case II study area is affected by the proximity of the Gee lease to the Vicksburg flexure zone. Structure maps across the study area for four marker horizons (figs. 8 through 11) reveal a strong structural overprint on the reservoir geology. Regional 2-D seismic reflection lines (fig. 29), cross sections B–B′ and C–C′ (figs. 32 and 33) and the structure maps (figs. 35 through 38) indicate that the intensity of faulting increases both at deeper reservoir drilling depths and across the study area in an east to

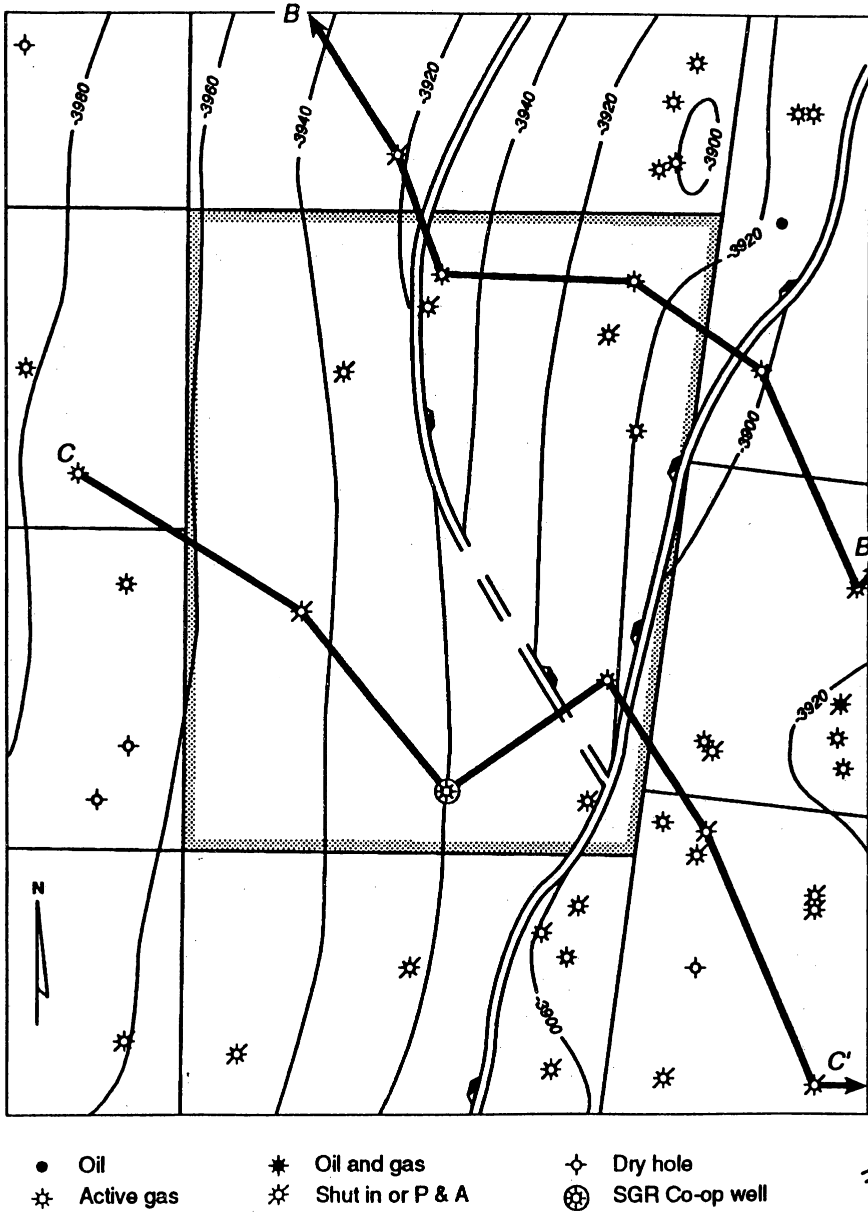
Table 4. Agua Dulce potential resource estimates, H. W. Gee lease, as of July 1991.

Reservoir Parameters							Resource Estimates				Resource Category
Reservoir	Depth ft	H Gross ft	A Area acre	Po psi	Temp deg F	Bgi scf/rcf	OGIP Mmcf	Rcvrbl GIP Mmcf	Cum Prod Mmcf	Remain Reserves Mmcf	Reservoir Terminology
4400	4420	4.8	300	1,980	145	133	420	336	0	336	Bypassed
4700	4720	11.0	240	2,115	151	141	811	649	0	649	Incompletely Drained
5200	5210	12.4	380	2,340	158	152	1,553	1,243	0	637	Incompletely Drained
5300	5300	19.3	380	2,385	160	154	2,461	1,969	814	1,155	Incompletely Drained
5400	5400	14.0	240	2,430	162	156	1,141	913	0	832	Untapped
5450	5450	14.0	240	2,453	163	157	1,148	918	0	692	Untapped
6050	6065	4.5	120	2,723	173	169	199	159	0	159	Bypassed
6300	6320	4.0	240	2,835	177	174	364	291	0	190	Bypassed
6500	6500	6.0	240	2,925	181	177	556	445	0	167	Incompletely Drained
6550	6550	9.6	240	2,948	181	178	894	715	213	502	Untapped
						Total*	9,547	7,637	1,027	5,319	

OGIP = 43.56*h*A*phi*(1-Sw)*Bgi

Temperature gradient = 1.7 deg F per 100 ft
Pressure gradient = 0.450 psi per ft
Gas gravity = 0.65 (air =1)
Porosity = 25%
Water Saturation = 45%
Net/Gross = 37%

*Totals may not equal sum of components due to independent rounding.



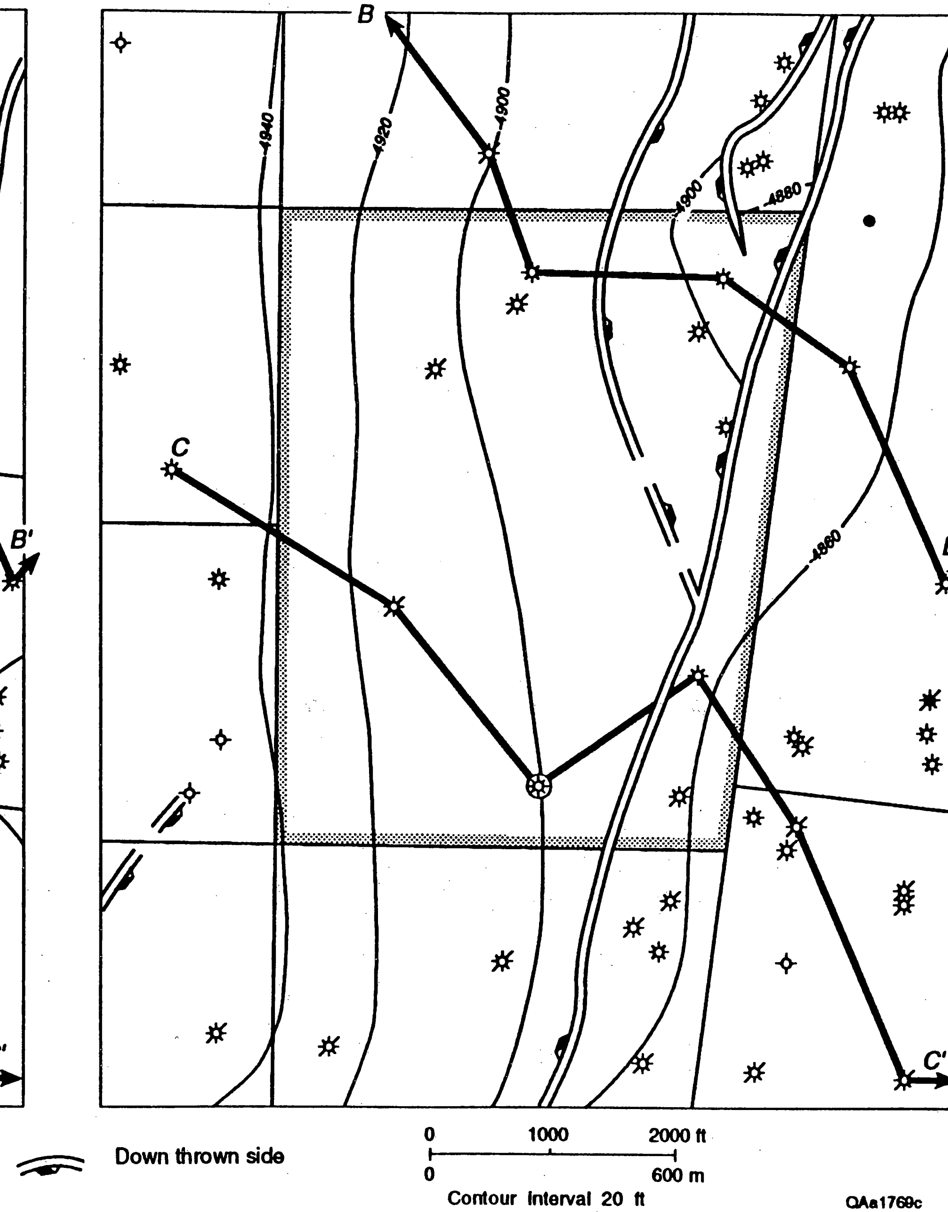


Figure 35. Structure map, top of the Frio Formation. Depths relative to sea level in feet.

Figure 36. Structure map, top of the Wright Sandstone Reservoir. Depths relative to sea level in feet.

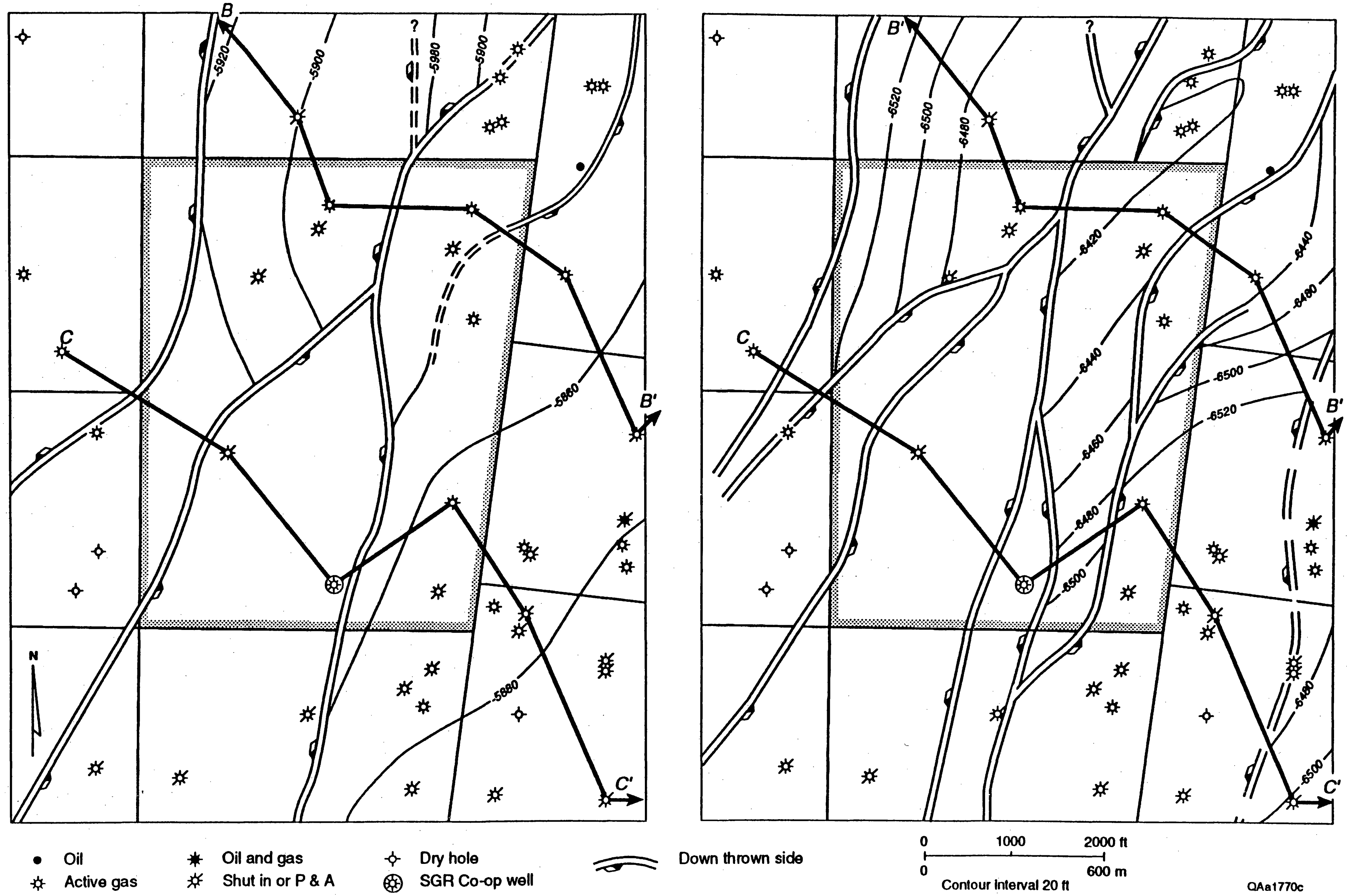


Figure 37. Structure map, top of the E-18 Reservoir. Depths relative to sea level in feet.

Figure 38. Structure map, top of the Dabney Reservoir. Depths relative to sea level in feet.

west direction. Comparison of the structure maps shows that the structural grain of the faults are primarily from north-northeast to south-southwest. Analysis of pressure-buildup well-test data clearly supports the concept of reservoir compartmentalization (which is partly attributed to fault segregation); reservoir compartmentalization is described in detail in the analysis of individual reservoirs. Fault segmentation of past producing and currently producing gas reservoirs has implications for the future development of the secondary gas resources in this area.

Table 4 summarizes reservoir parameters used for evaluation of original gas in place by volumetric methods. The results of reservoir evaluation for original gas in place and remaining gas in place are also summarized in table 4. Ten reservoirs were evaluated to determine the size of the original and remaining resource. Estimated resources for individual reservoirs ranged from 100 to greater than 2,400 Mmcf in the Gee lease in Agua Dulce field. The original recoverable gas in place was estimated at 9.6 Bcf. The recoverable gas in place was estimated to be 7.6 Bcf. As of July 1, 1991, the combined cumulative production from these 10 reservoirs was 1.0 Bcf. Remaining reserves are estimated to be 5.3 Bcf. The remaining reserves are less than the recoverable gas in place minus the cumulative production because of drainage beyond the limits of the Gee lease (table 5).

Examples of Incremental Gas Resources

Each of the reservoir examples was identified by the procedure described in the previous section. Three of the 10 separate reservoir intervals were selected to illustrate the spectrum of secondary gas resource types detected in the case II study area. The three examples use the reservoir evaluation methods, which combine geology, reservoir engineering, petrophysics, and geophysics to evaluate the incremental gas resource. Of the 10 reservoir intervals evaluated, 3 are classified as bypassed, 3 are untapped reservoirs, and 4 are considered incompletely drained reservoirs (fig. 5). The examples are referred to by reservoir name and are presented in descending stratigraphic order as the 4,420-ft reservoir (a thin bypassed reservoir), the 5,300-ft reservoir (an incompletely drained reservoir), and the 6,550-ft reservoir (an untapped reservoir compartment).

Table 5. Case II—Agua Dulce field: risked reserves.

Risked Reserves Summary as of July 1991											
Reservoir/ Zone	Original GIP Mmcf	Rcvrbl GIP Mmcf	Cum Prod Mmcf	Remain Reserves Mmcf	Dvlpd Remain Reserves Mmcf	Undvlpd Remain Reserves Mmcf	Dvlpd Risk Factor	Undvlpd Risk Factor	Risked Dvlpd Mmcf	Risked Undvlpd Mmcf	Risked Total Mmcf
4400	420	336	0	336	336	0	100%	0%	336	0	336
4700	811	649	0	649	0	649	0%	66%	0	428	428
5200	1,553	1,243	0	637†	0	637	0%	66%	0	420	420
5300	2,461	1,969	814	1,155	400	755	100%	66%	400	498	898
5400	1,141	913	0	832†	0	832	0%	33%	0	275	275
5450	1,148	918	0	692†	0	692	0%	33%	0	228	228
6050	199	159	0	159	0	159	0%	33%	0	52	52
6300	364	291	0	190†	0	190	0%	33%	0	63	63
6500	556	445	0	167†	1	166	100%	66%	1	110	111
6550	894	715	213	502	30	472	100%	66%	30	312	342
Total*	9,547	7,637	1,027	5,319†	767	4,552			767	2,386	3,153

*Totals may not equal sum of components due to independent rounding.
†The remaining reserves are less than the recoverable GIP minus the cumulative production because of drainage beyond the limits of the Gee lease. For further discussion, see page 77.

4,420-Ft Reservoir (Thin Bypassed Reservoir)

This reservoir is an example of a thin-bed bypassed reservoir identified by log analysis in the Lou Little No. 7 well (figs. 31 and 34). Evaluation of postcompletion well control indicates that virtually all wells in the study area had previously penetrated the reservoir interval. No known production had been reported by previous operators in this reservoir interval, which was identified from all well log data available. Clues from the modern open-hole log (in the Gee No. 7 well) and sidewall core data included (1) a slight gas indication of gas, (2) the original reservoir pressure measured in the wireline tester log, and (3) an indication that this zone should be gas productive (through a comparison of the computed-log water saturations and critical water saturations).

The evaluation led to an SGR project recommendation for recompletion in a thin-bed interval. The Gee No. 7 well was completed from 4,416 to 4,420 ft in April 1992. The maximum initial producing rate from the completion was 1,200 mcf/d, with a flowing wellhead pressure of 1,240 psi. The trend of gas-production rate versus time for this bypassed reservoir is indicated in figure 39. Completion pressure confirmed original reservoir pressure, which is consistent with the expectation for a previously bypassed reservoir that has no history of prior production. Data available included a modern log suite of dual induction with density-neutron–gamma ray (GR) combination, sidewall cores, and wireline formation tester pressures. Figure 40 shows the integrated computed results in this sandstone. The evaluation showed a porosity of 27 percent, a water saturation of 52 percent, a resistivity of 2 ohm-m, and low GR values, indicating good permeability (type I sandstone of Grigsby and Kerr, 1991). This thin bed is found between two higher resistivity beds that have very low porosity. The wireline tester measured highly variable pressures of 1,960 psi (permeable) and 155 psi (tight) (fig. 41). The sidewall core analysis indicated permeabilities that range from 1 to 71 md and an estimated critical water saturation (S_{wcr}) of 60 to 71 percent (fig. 40). Gas was indicated in the sidewall cores, and a slight crossover was noticed in the porosity logs. The computed water saturation was shown to be lower than the critical water saturation from cores. Because the effective bed thickness of the porous zone is less than 4 ft, the log response was

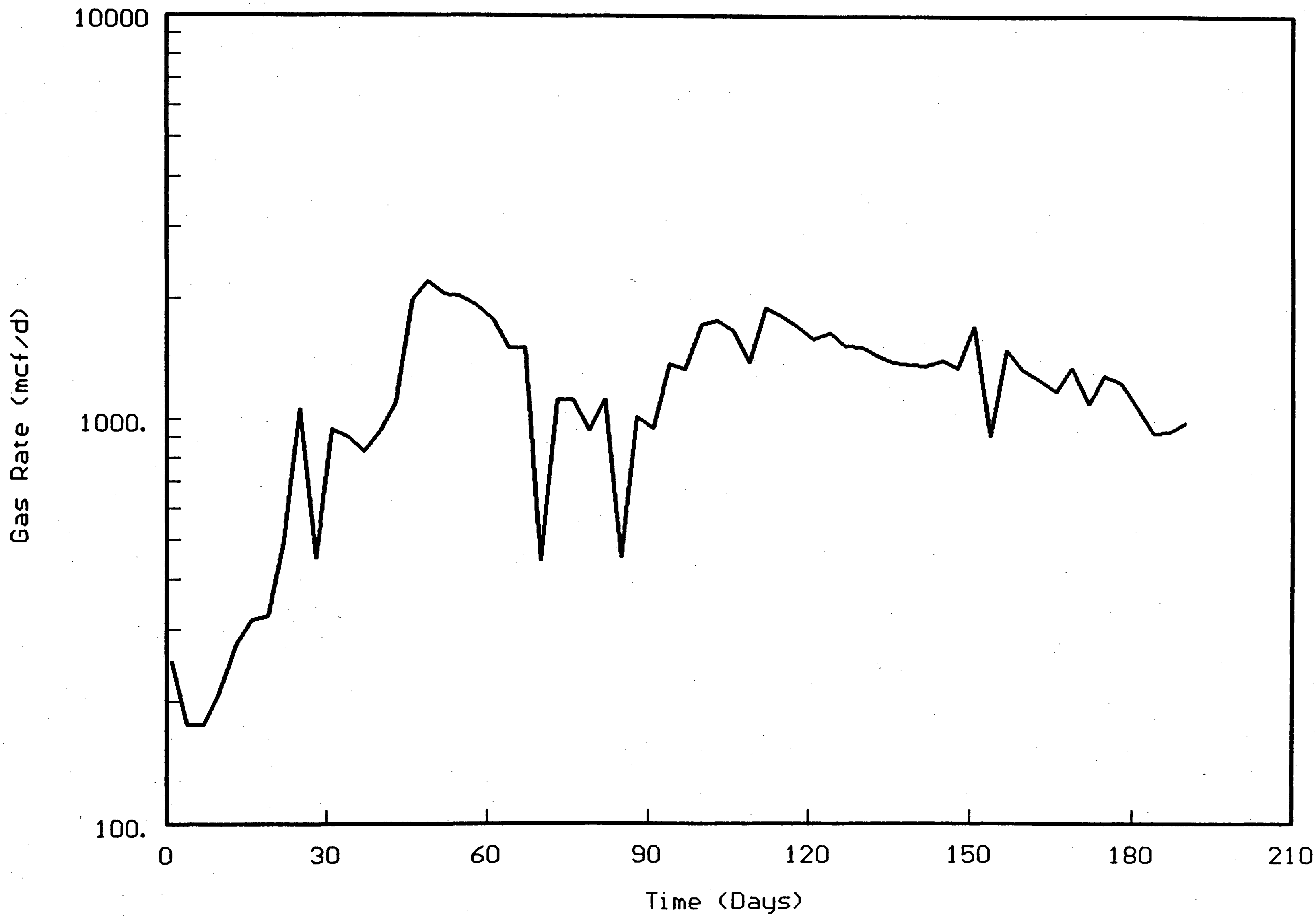
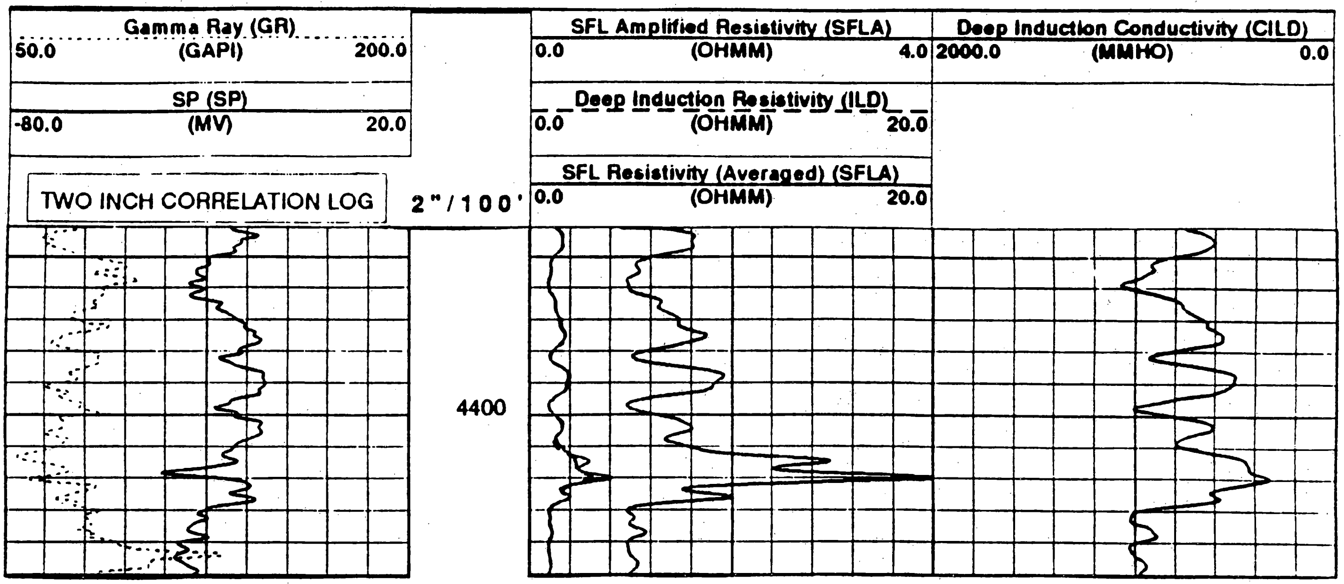
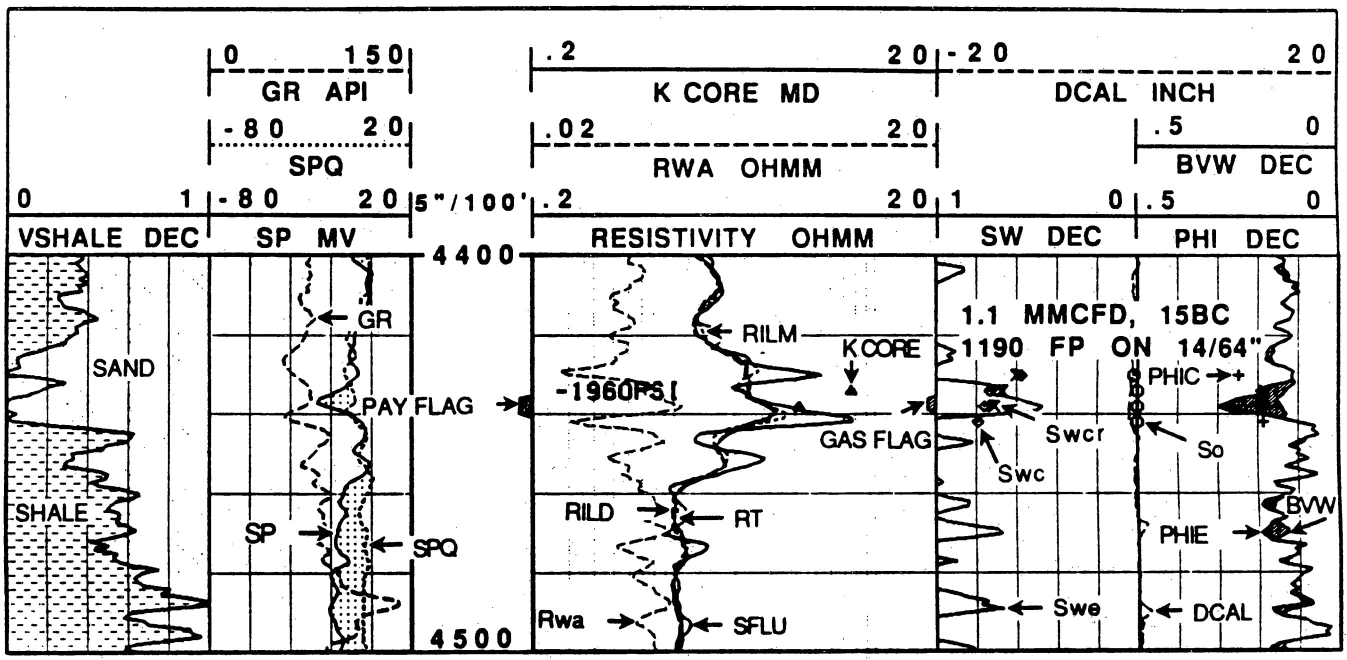


Figure 39. Production plot of average daily gas production rate for the 4,420-ft reservoir from April 1992 to August 1992 for the Gee No 7 well.

(a)



(b)



(c)

SIDEWALL CORE ANALYSIS REPORT

DEPTH FEET	PERM MD(KA)	POR. %	OIL% VOL.	GAS% VOL.	OIL% PORE	WTR% PORE	PROD. PROD.	API	GAS UTS	REC IN.	DESCRIPTION	CRT WTR
3054.0	298.0	27.9	0.0	7.3	0.0	73.8	WATER		0	1.0	F-VFG V LMY SD, NO FLU	42
3070.0	402.0	28.0	0.0	7.1	0.0	75.3	WATER		0	1.0	FG V LMY SD, NO FLU	41
4415.0	71.0	24.9	0.4	10.1	1.6	57.8	GAS		61	1.2	F-VFG SLI SHY LMY SD, NO FLU	60
4417.0	7.6	19.4	0.0	5.2	0.0	73.2	LOWPERM		3	0.5	VFG SILTY DIRTY V LMY SD, NO FLU	67
4419.0	4.2	19.0	0.0	4.6	0.0	75.8	LOWPERM		5	0.7	VFG SILTY SHY V LMY SD, NO FLU	71
4421.0	0.0	18.6	0.0	3.9	0.0	79.0			5	1.0	SAME AS ABOVE	

Figure 40. (a) Standard 2-inch well log response, (b) detailed computed log, and (c) core analysis of 4,420-ft reservoir in the Gee No. 7 well.

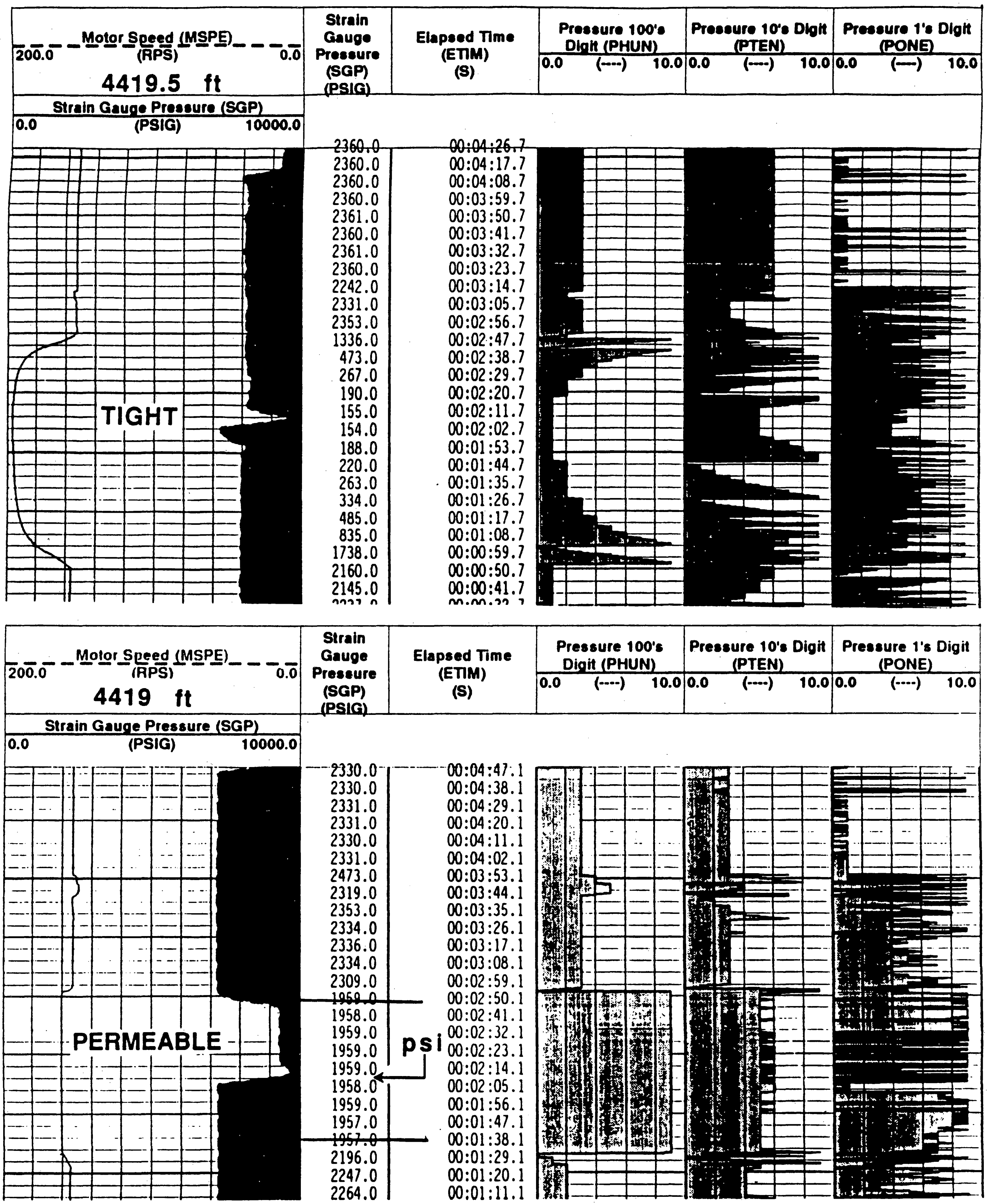


Figure 41. Response of well log pressure tester for permeable and tight intervals.

generally pessimistic. On the basis of the integrated formation analysis, the zone appeared favorable for completion testing.

The resource potential is projected at an ultimate recovery of 320 Mmcf/g. The pressure data also indicate a drainage area of about 200 acres with an original gas in place of about 400 Mmcf (fig. 42). A net-sandstone-thickness map indicates that the 4,420-ft sandstone consists of narrow, southeast-trending belts (500 to 2,000 ft wide) of a single, thin sandstone (commonly only 5 ft thick) that pinches out into broad areas of inferred floodplain mudstone (fig. 43). The 4,420-ft sandstone in this part of the Gee lease lies along the crest of a rollover anticline that is bounded on two sides (east and west) by faults with sufficient offset (20 ft or more) to structurally isolate the sandstone (figs. 32 and 43). Pressure-buildup tests indicated that the reservoir has a maximum permeability thickness of about 100 md-ft in the 4-ft interval. The pressure-buildup tests also indicated a nearby barrier at a distance of about 500 ft. This matched the distance to a fault mapped from well control and east of the Gee No. 7 well. Stratigraphic isolation of the 4,420-ft sandstone also occurs where the sandstone pinches out southwestward and northeastward from the wells (fig. 43). This sandstone is not continuous and is potentially compartmentalized across field. For example, in the Gee No. 8 well it is absent, whereas in the Gee No. 6 well it is a tight low-porosity reservoir. Tight zones recorded by the wireline formation tester also indicate the lack of vertical permeability inside the reservoir. If these tests had not been repeated in a permeable zone, the sand could have been ignored and deemed nonproductive. The sidewall permeabilities also confirm an intercalation of permeable zones with tight zones.

Following the SGR project recommendation for recompletion research in this thin-bed interval, the Pennzoil Gee No. 4 and Union Producing Kerr No. 5 wells were successfully completed into this bypassed reservoir. The rate projections and economic analysis of this reservoir example are presented for this case history.

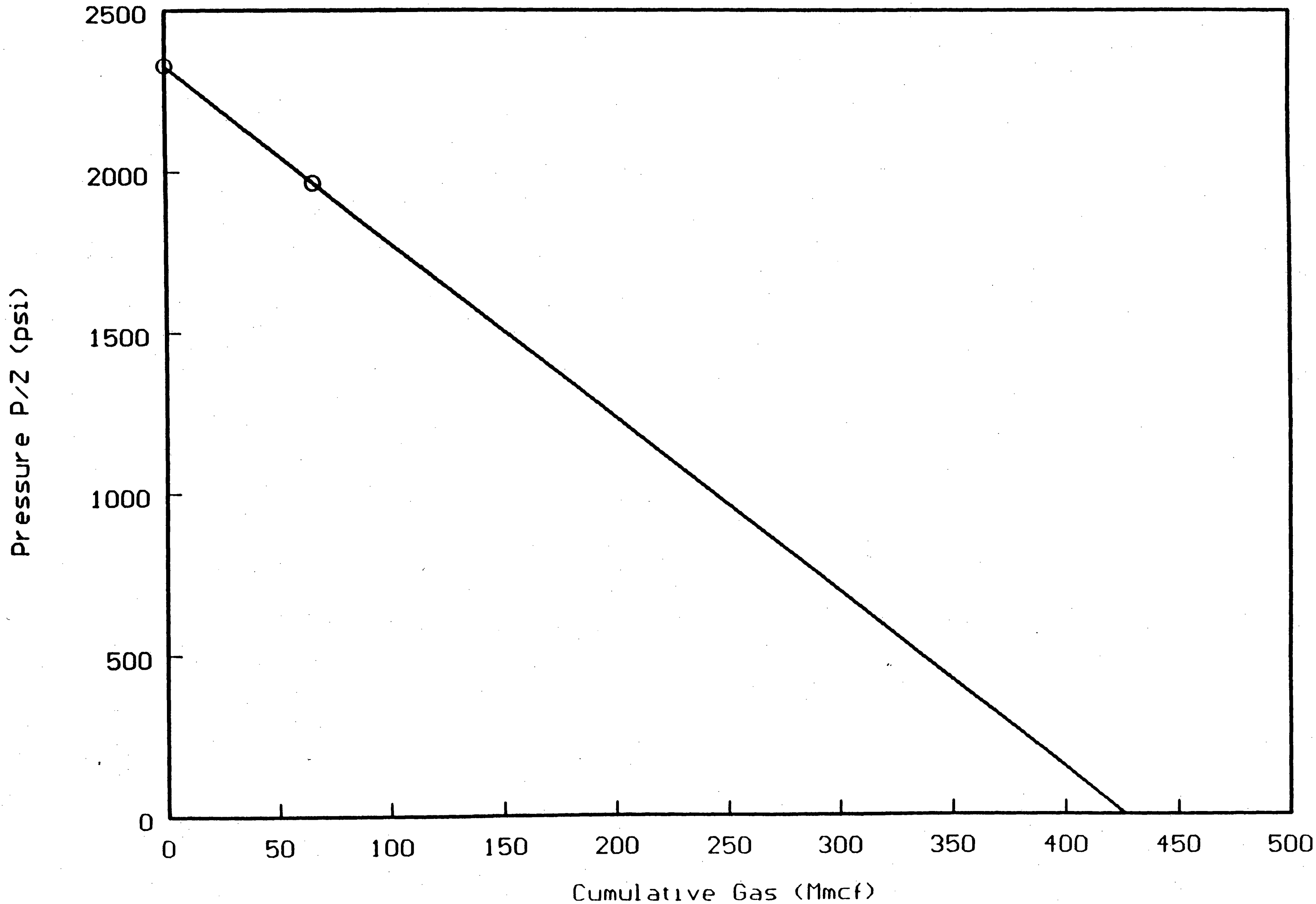


Figure 42. Pressure history (P/Z) versus cumulative gas production for the 4,420-ft reservoir for the Gee No. 7 well.

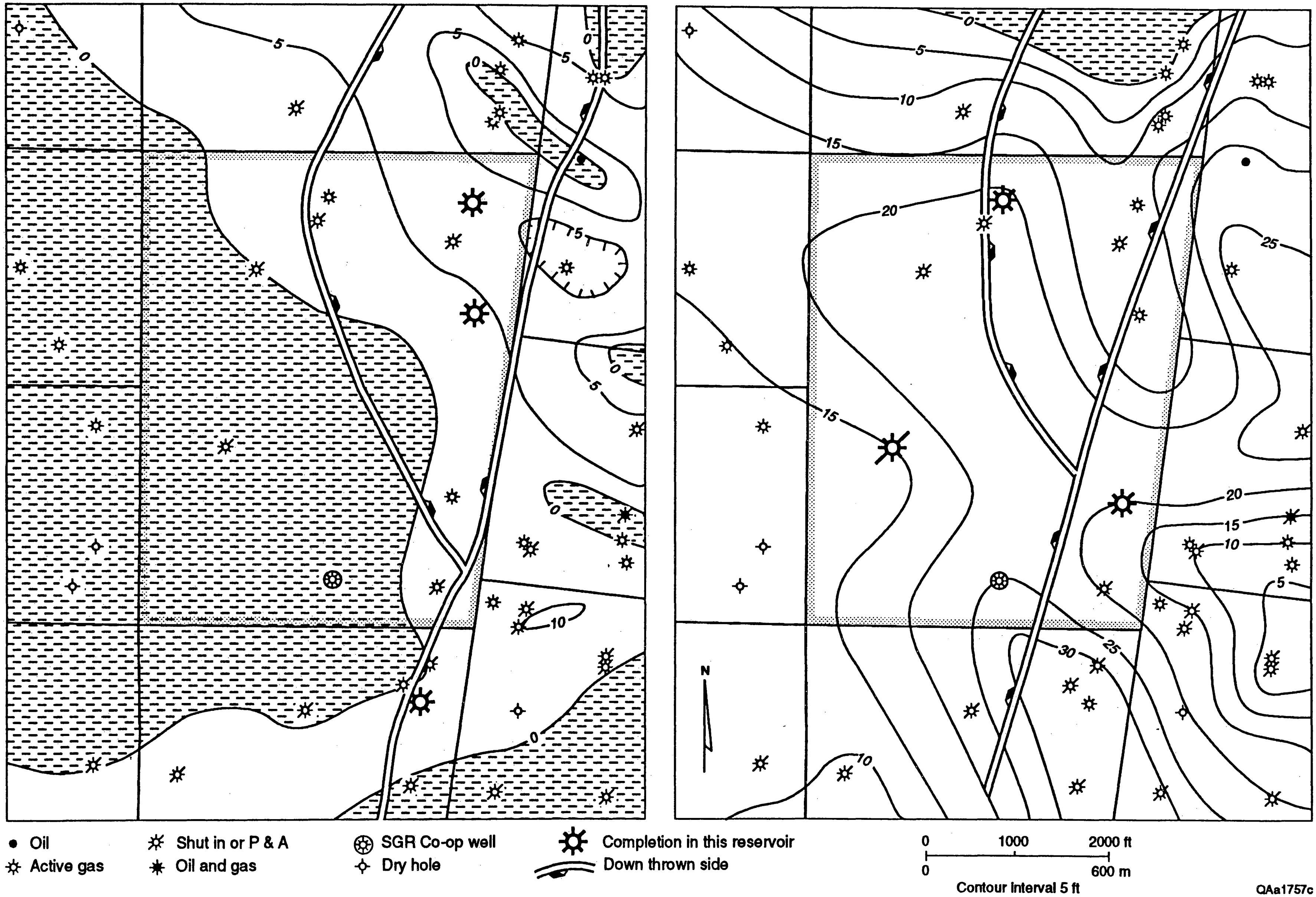


Figure 43. Map of gross sandstone in the 4,420-ft reservoir.

Figure 44. Map of gross sandstone in the 5,300-ft reservoir.

5,300-Ft Reservoir—Incompletely Drained Reservoir Compartment

The 5,300-ft reservoir (also termed the C-50 reservoir in the Agua Dulce field) is an example of an incompletely drained reservoir compartment identified by comparisons of previous production from nearby wells and by measured reservoir pressure.

The 5,300-ft sandstone (C-50 reservoir) lies across the whole Gee lease, and mapping of the reservoir horizon indicates that the sandstone thickness ranges from less than 15 to more than 20 ft (fig. 44). The reservoir zero edges are at the north part of the study area. Electric log facies interpretation suggests that the 5,300-ft reservoir is potentially a fluvial channel system; the gross-sandstone-isopach map reflects the potential depositional axes of these trends. Structural segmentation or intrareservoir barriers are critical in creating compartments in this reservoir. The location and projected direction of faults, also shown in figure 44, indicate that the 5,300-ft sandstone in the northeast part of the lease is segmented by faults, creating a small graben that trends north to south (fig. 29). The east margin of the graben is created by the antithetic fault that trends north to south. The Gee No. 6 well was completed in the 5,300-ft reservoir from 5,307 to 5,317 ft on July 14, 1991, for an initial potential of 576 mcf/d at a flowing wellhead pressure of 784 psi (fig. 30). The gas-production rate versus time plot is shown in figure 45. The initial static reservoir pressure was 1,623 psi, which indicated an incompletely drained reservoir. This reservoir has now produced from three wells (the Gee No. 6, Union Producing Gee No. 2, and Pennzoil Gee No. 5 wells) in the Gee lease (fig. 30). The 5,300-ft reservoir was previously produced from 1971 to 1979 by the Gee No. 2 well, which had a reported cumulative gas production of 813 Mmcf. The Gee No. 2 well is about 0.75 mi from the Gee No. 6 well. The initial pressures of the other completions were not available.

Evaluation of the structural and stratigraphic configuration of the reservoir and the production-decline rate behavior indicated a potential secondary gas resource. The Gee No. 6 well was perforated in July 1991 and is still active (cumulative production to January 1, 1993, is 177 Mmcf). The operator performed three pressure-buildup tests, which indicated an effective

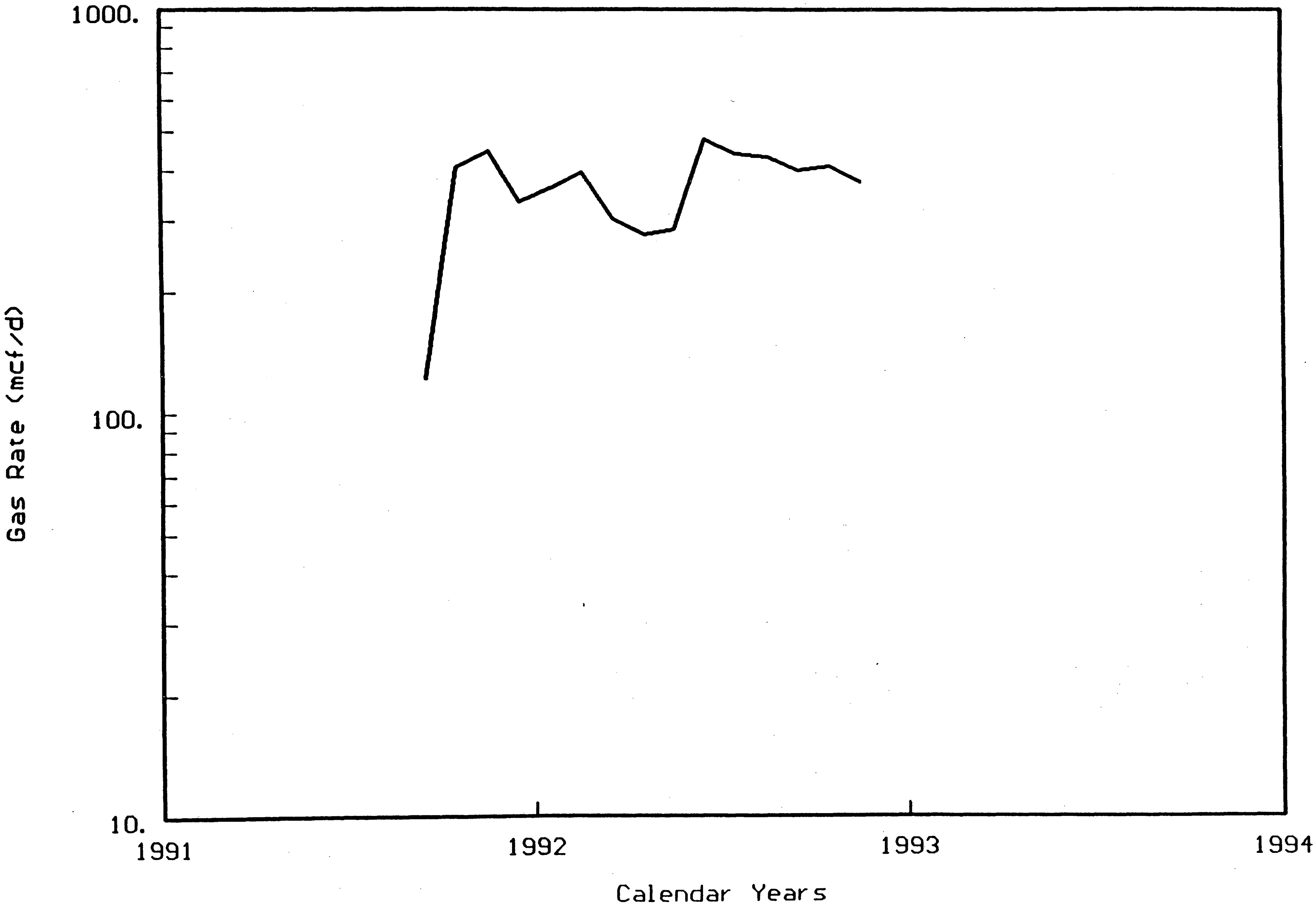


Figure 45. Production plot of average daily gas production rate for the 5,300-ft reservoir from September 1991 to August 1992 for the Gee No. 6 well.

permeability to gas of 2.5 md for the 13-ft reservoir interval. The pressure-buildup data were interpreted to indicate a long-narrow drainage shape with a width of 300 ft or less. The pressure-buildup tests indicate a small primary drainage volume with recoverable reserves of 400 Mmcf at the time of completion. Pressure history for the Gee No. 6 well is shown in figure 46.

Production from the Gee No. 6 well is a consistent 500 mcf/d in the 5,300-ft reservoir. Evaluation of logs indicated that this reservoir has a high degree of variability in reservoir and fluid properties. Figure 34a shows both the standard logs and the computed logs in this interval for 5,305 to 5,311 ft. The average petrophysical parameters are porosity, 24 percent; water saturation, 40 percent; bulk volume of water, 0.10; resistivity, 6 ohm-m; and estimated net pay interval, 13 ft. The top of this sand is at 5,193 ft below mean sea level in the Gee No. 6 well. The small values for water saturation and bulk volume of water suggest a productive interval. Presence of gas is also confirmed by the crossover in the porosity logs.

In the Gee No. 7 well, the 5,300-ft reservoir (C-50 sandstone) is 25 ft upstructure from Gee No. 6 well, but the computed results in the interval from 5,280 to 5,290 ft show that the reservoir consists of lesser quality rock (fig. 34b). Log porosity ranges from 12 percent to 19 percent, with increased water saturations of 55 percent, and a variable bulk volume of water. The volume of shale (V_{sh}) is generally higher than that in the Gee No. 6 well. The sidewall analysis indicated permeabilities ranging from 3 to 24 md, and wireline pressure test indicated a pressure of 1,054 psi. No evidence of gas was observed in the porosity logs. This zone, a low-permeability hydrocarbon zone, may need to be stimulated to produce.

In the Gee No. 8 well (fig. 34c) the 5,300-ft reservoir (C-50 sandstone) is downdip from the Gee No. 6 well in the interval from 5,340 to 5,360 ft, and the log analysis shows it to be water productive, having a bulk volume of water of 0.15 and a computed water saturation equal to the sidewall core critical water saturation. No gas or hydrocarbons were inferred from the sidewall analysis results. This well is near the Gee No. 2 well, which has produced from the 5,300-ft reservoir and which has possibly drained the area near the Gee No. 8 well.

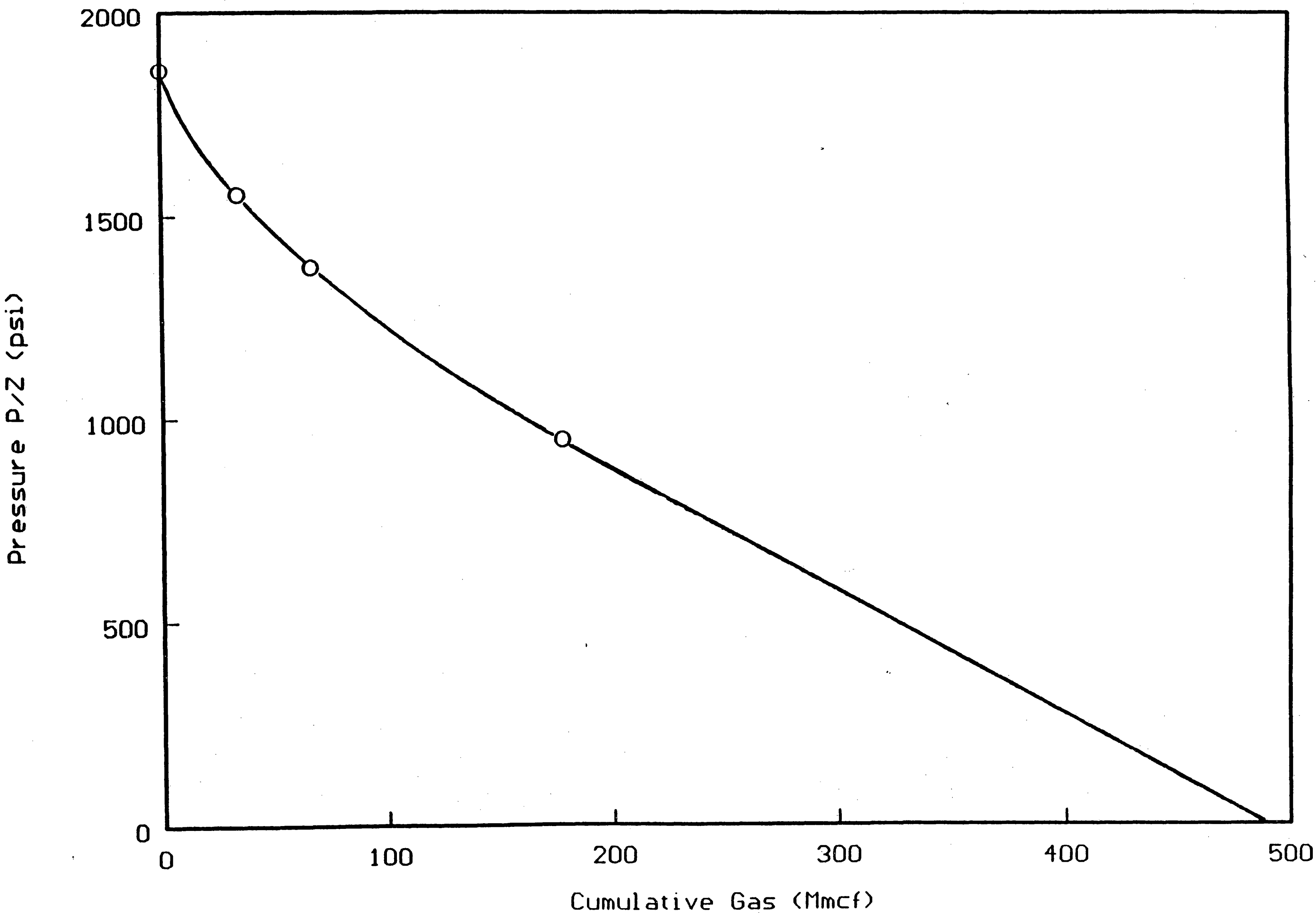


Figure 46. Pressure history (P/Z) versus cumulative gas production for the 5,300-ft reservoir for the Gee No. 6 well.

6,550-Ft Reservoir–Untapped Reservoir Compartment

The 6,550-ft reservoir (also named the Wolters reservoir) is an example of an untapped reservoir compartment identified in the Gee lease (fig. 30). The Gee No. 8 well was targeted for the evaluation of multiple reservoirs, including the opportunity to analyze fault-separated compartments in the Wolters reservoir. This reservoir was completed in the third infield well (the Gee No. 8 well [fig. 34b]) from a depth of 6,561 to 6,571 ft on October 10, 1992, in a reservoir compartment that was untapped by previous completions on the Gee lease and offset leases. Interpretation of SP well log response suggested that reservoir genesis in the south part of the study area is from fluvial channel-fill deposits (fig. 47a and b). The Gee No. 8 well is in a channel trend and between wells that had previously produced from the 6,550-ft reservoir. This northwest-southeast trend of five wells is about 1 mi long. The combined cumulative production is about 5,800 Mmcf, and production per well is as much as 1,800 Mmcf.

Log responses in the Gee No. 8 well (fig. 34c) indicated that no particular problem exists in evaluating this zone by log analysis; resistivity is 10 ohm-m, SP has a good deflection, and the GR log indicates a low shale content. Computed logs indicated an average porosity of 19 percent, water saturation of 34 percent, and bulk volume of water of 6 percent, with the top of this sandstone at 6,439 ft below mean sea level. The net pay thickness in this well is 14.5 ft. A pressure of 3,066 psi was obtained from wireline pressure, and production of water-free gas was interpreted from the fluid sample analysis. The rapid decline in shut-in pressure to 2,270 psi after the zone was put in production indicated a reservoir of limited size but not connected to the adjacent production in the Union Producing Company Gee No. 2 well.

In the Gee No. 7 well, this sandstone was found to be structurally higher by 50 ft. The sandstone quality, however, seems to have degraded because the log analysis indicated a lower average porosity of 15 percent. A sidewall sample indicated a 0-md permeability of a very fine grained sandstone (no oil was found in this sample). This sandstone is a very low permeability zone and may need stimulation to produce. Furthermore, the nearby UPRC Anderson No. 1 well has

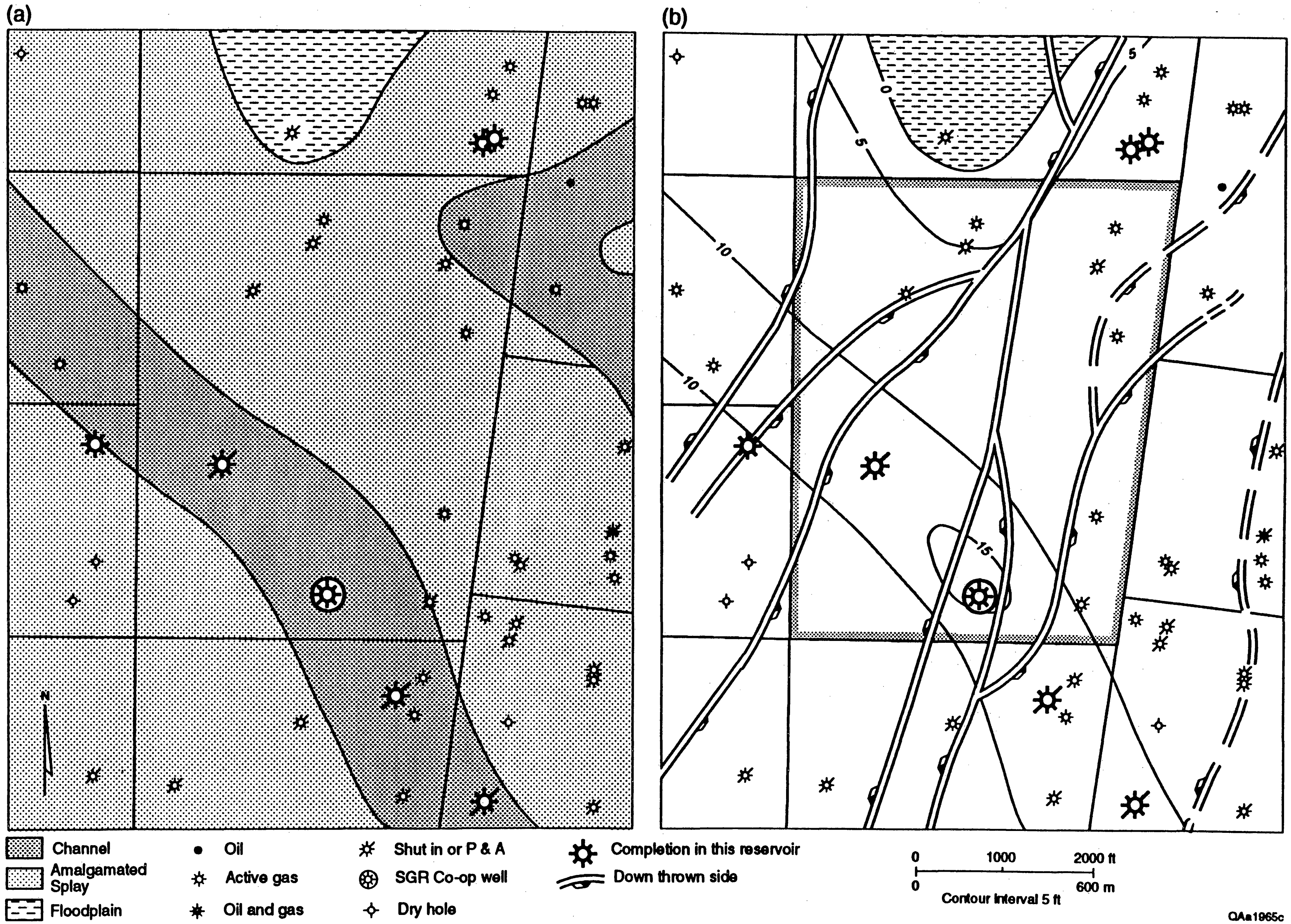


Figure 47. Map of (a) depositional facies and (b) gross sandstone in the 6,550-ft reservoir.

already produced 0.19 Bcf near this well. In the Gee No. 6 well, the same sandstone is not present; the well also is on the other side of a fault (fig. 47).

A wireline formation test performed in October 1992 measured the initial reservoir pressure of the 6,550-ft reservoir in the Gee No. 8 well at about 3,071 psi. A pressure-buildup test performed after 3 weeks of production determined that the reservoir pressure had declined to about 2,200 psi, with a cumulative production of 16 Mmcf. The buildup test and cumulative production were used to estimate a drainage area of less than 10 acres. The reservoir permeability was determined to be 3.5 md over the 15-ft interval. The completion in the 6,550-ft interval was depleted in January 1993 after producing only 30 Mmcf. The pressure-buildup test suggested the presence of multiple nearby boundaries. The shapes of the pressure curves were matched to a long and narrow drainage shape that was less than 150 ft wide. The long and narrow drainage shape is attributed to closely spaced faults that compartmentalize this reservoir.

RESOURCE ECONOMICS AND BENEFITS

For both case studies, the costs of current and future development, estimation of reserves, and recovery of secondary gas resources were evaluated. Assumptions about future gas prices and projections of gas reserve appreciation that could be achieved were required to evaluate the costs and benefits of infield development. The reserve and economic projections are consistent with standard engineering methods and known operational practices used by many gas operators. In both case studies, the gas operators provided information about the costs of drilling additional wells and recompletions. The produced and projected reserves and economics of these two case studies—presented for comparison—indicate that these types of reservoirs are an economic source of gas resources in mature fields.

The McFaddin "A" lease in the North McFaddin field includes approximately 1,800 acres. For the 11 reservoir intervals analyzed, the original gas in place is 27,352 Mmcf, with an estimated recoverable gas in place of 20,269 Mmcf. As of February 1992, 8,063 Mmcf had been produced and the reserves was 12,207 Mmcf. The SGR risked reserves were estimated at 6,456 Mmcf of recoverable gas (including risking [see "Risk Assessment," p. 96]). Of these reserves, 2,396 Mmcf has been developed since February 1992. An additional 4,060 Mmcf remains to be developed. The capital cost to develop these reserves is estimated to be $1,450,000, or $0.22 per mcf, which includes drilling and completion of wells, recompletion of existing wells, and SGR project team costs. The total cost to develop and produce the reserves is determined to be $3,768,000, or $0.58 per mcf, excluding royalties, and includes capital costs, operating costs, and severance and ad valorem taxes (table 6). These cost estimates are calculated using risk-weighted reserves. The corresponding cost estimates using unrisked reserves would be $0.12 per mcf in capital cost and $0.31 per mcf in total cost.

In comparison, the Gee lease in the Agua Dulce field covers about 490 acres, about one-third the size of the McFaddin "A" lease in the North McFaddin field. For the 10 reservoir intervals

Table 6. Projected reserves and cashflow—North McFaddin field.

Year	Number Wells	Gross Prod. Mmcf	Net Prod. Mmcf	Gas Prices $/mcf	Oper. Revenue $M*	Oper. Expense $M	Sev. + Adv. Tax $M	Capital Costs $M	Pre-tax Cashflow $M	Cumul. PW at 7% $M	Cumul. PW at 10% $M
1991	0	0	0	0	0	0	0	0	0	0	0
1992	4	694	607	2.00	1215	48	121	1450	-405	-378	-368
1993	8	885	775	2.00	1549	96	155	0	1298	756	705
1994	8	721	631	2.00	1262	96	126	0	1040	1604	1486
1995	8	523	457	2.00	915	96	91	0	727	2159	1983
1996	8	379	332	2.00	664	96	66	0	502	2517	2294
1997	8	276	241	2.00	483	96	48	0	339	2743	2486
1998	8	685	599	2.00	1199	96	120	0	983	3355	2990
1999	8	816	714	2.00	1428	96	143	0	1189	4046	3544
2000	8	524	459	2.00	917	96	92	0	730	4443	3854
2001	7	364	318	2.00	637	84	64	0	489	4692	4042
2002	7	258	226	2.00	452	84	45	0	323	4845	4156
2003	7	183	161	2.00	321	84	32	0	205	4936	4221
2004	7	113	99	2.00	198	84	20	0	95	4976	4248
2005	3	35	30	2.00	61	36	6	0	19	4983	4253
Totals		6,456	5,650		11,301	1,188	1,130	1,450	7,533		

<u>Economic Indicators</u>

Present Worth Ratio at 7%	3.44	P.W. Cum Cashflow / Capital Cost
Present Worth Ratio at 10%	2.93	P.W. Cum Cashflow / Capital Cost
Capital Cost/Mcf (Gross)	$0.22	
Total Cost/Mcf (Gross)	$0.58	Excluding royalties
Total Cost/Mcf (Net)	$0.67	After royalties

Summary of Capital Costs $M	Projected Number	Average Cost	Total Cost
Drilling and Completion of Wells	4	$250	$1,000
Recompletion of Existing Wells	12	$25	$300
SGR Project Team Costs			$150
Total Costs			$1,450

*$M denotes thousands of dollars.

analyzed, the original gas in place is 9.547 Mmcf, having an estimated recoverable gas in place of 7,637 Mmcf. As of July 1991, 1,027 Mmcf had been produced from these 10 reservoir intervals at the Gee lease. Some of these 10 intervals had been produced by nearby wells on the offsetting leases, which resulted in some pressure depletion despite little or no previous production at the Gee lease. The remaining potential reserves were estimated, where possible, using the current reservoir pressures inferred from wireline tests and well tests. The remaining reserves are estimated at 5,319 Mmcf (table 5). This volume is less than the difference between the recoverable gas in place and cumulative production because of the partial depletion from offset wells across the lease boundary. The total SGR risked remaining reserves are estimated at 3,153 Mmcf (table 5). Of these reserves, 767 Mmcf had been developed from July 1991 through October 1992 and approximately 2,386 Mmcf remains to be developed. The capital cost to develop these reserves is estimated at $1,575,000, or $0.50 per mcf. The total cost to develop and produce the reserves is determined to be $2,607,000 or $0.83 per mcf, excluding royalties. These cost estimates are calculated using risk-weighted reserves. The corresponding cost estimates using unrisked reserves would be $0.30 per mcf in capital cost and $0.49 per mcf in total cost.

Estimation of Economically Recoverable Reserves

Each study area was evaluated for production potential within stratigraphic intervals that previously produced on the lease or adjacent leases. Twenty-one reservoir intervals—11 from the McFaddin "A" lease in the North McFaddin field and 10 from the Gee lease in the Agua Dulce field—were evaluated for remaining reserve appreciation. A summary of these identified potential reserves is shown for the McFaddin "A" lease, case I study area (table 3), and for the Gee lease, case II study area (table 5). The original gas in place for each reservoir was assessed by volumetric methods and integrated with all available reservoir pressure data. The recoverable gas in place was determined by applying a reservoir-unit recovery factor from 60 to 80 percent, depending on the type of productivity and drive mechanism used. Recoverable gas in place is the quantity of gas that can be produced from original pressure to some final abandonment pressure at an economic flow rate. The permeability thickness (kh) of the reservoirs studied is sufficient to justify a recovery factor of 80 percent and an abandonment reservoir pressure of 200 to 400 psi. The recoverable gas calculations assume that the productive reservoir has enough completions to effectively contact all of the recoverable gas. Previous production in each study area was tabulated for each prospective reservoir and was subtracted from the recoverable gas to determine the estimate of remaining reserves. Where there was no record of prior production in the study area for a specific reservoir, but the reservoir pressure data indicated partial depletion from the adjacent leases, the remaining recoverable reserve was adjusted using the current reservoir pressure. The remaining recoverable reserves were further categorized into developed and undeveloped. A reservoir must have one or more currently producing completions to have developed remaining reserves. The undeveloped recoverable gas is the quantity of remaining gas after subtracting the developed reserves from the total remaining reserves.

Risk Assessment

Three categories of risk factors were applied to the remaining recoverable gas: (1) a risk factor of 100 percent was applied where there was enough production and pressure data from active completions to determine the remaining reserves with confidence, (2) a risk factor of 66 percent was applied to recoverable reserves where the reservoir was producing or had previously produced, but there was insufficient data to determine if existing completions could produce all the recoverable resource or whether additional completions were required, and (3) a risk factor of 33 percent was applied to potential reservoir intervals that have no prior production but where logs, core, and reservoir similarity indicate that production is possible. The risked reserves are the product of the remaining recoverable gas and the assigned risk factor. The application of these risk factors to the recoverable reserve estimates is shown in table 3 for case I and in table 5 for case II.

Economic Factors

The reserve and economic projections are based on the beginning of SGR development by each of the operators in these case studies. The development of North McFaddin field began in February 1992, and the development of Agua Dulce field began in July 1991. A fixed gas price of $2.00 per mcf was projected over the remaining production life. Production taxes were estimated at 10 percent of net revenues. Direct operating costs were estimated to be $1,000 per month per producing well. Drilling and initial completion costs of new wells were expected to be $250,000, and the costs to recomplete a well in a prospective reservoir were expected to average $25,000. The recompletion costs were estimated from the expectation that actual workover cost would range from $10,000 to $30,000 and that some recompletion attempts would be unsuccessful. Total development cost was assumed to be incurred in the first year of the economic evaluation. The net revenues and cashflow were based on a 100-percent working interest, burdened with a standard 12.5-percent royalty. Evaluation costs performed by the SGR project for each case study were allocated at $150,000 for each study area. This cost reflects the allocation of four project team members, incremental pressure tests, incremental well logs, and processing of the data.

Tables 6 and 7 show the tabulated reserves and economic summaries for the case I and case II study areas. The tabulations show the production and cashflow by year. The number of wells indicates the historical and projected active wells. Gross production is the risked economically recoverable annual lease production, and the net production is after a standard 12.5-percent royalty. Direct operating expenses are $12,000 per year per active well. Severance and ad valorem taxes make up 10 percent of the net revenues. The capital costs have been scheduled to occur in the first year of the evaluation, to allow a consistent comparison between study areas. Pre-tax cashflow (before federal income tax) is the net revenue minus direct operating costs, severance and ad valorem taxes, and capital costs. Cumulative present-worth calculations have been performed by discounting at 7 and 10 percent per year.

Table 7. Projected reserves and cashflow—Agua Dulce field.

Year	Number Wells	Gross Prod. Mmcf	Net Prod. Mmcf	Prices Gas $/mcf	Oper. Revenue $M*	Oper. Expense $M	Sev. + Adv. Tax $M	Capital Costs $M	Pre-tax Cashflow $M	Cumul. PW at 7% $M	Cumul. PW at 10% $M
1991	1	152	133	2.00	267	12	27	1575	-1347	-1259	-1224
1992	2	367	321	2.00	642	24	64	0	554	-741	-721
1993	4	567	496	2.00	992	48	99	0	845	-3	-23
1994	5	280	245	2.00	491	60	49	0	382	308	264
1995	5	282	247	2.00	494	60	49	0	384	601	526
1996	5	259	227	2.00	453	60	45	0	348	849	742
1997	5	521	456	2.00	911	60	91	0	760	1356	1171
1998	5	275	241	2.00	482	60	48	0	374	1589	1363
1999	4	271	237	2.00	474	48	47	0	378	1809	1540
2000	2	123	108	2.00	215	24	22	0	170	1901	1612
2001	1	39	34	2.00	69	12	7	0	50	1926	1631
2002	1	17	15	2.00	29	12	3	0	14	1933	1636
Totals		3,153	2,759		5,518	480	552	1,575	2,911		

Economic Indicators

Present Worth Ratio at 7%	1.23	P.W. Cum. Cashflow / Capital Cost
Present Worth Ratio at 10%	1.04	P.W. Cum Cashflow / Capital Cost
Capital Cost/Mcf (Gross)	$0.50	
Total Cost/Mcf (Gross)	$0.83	Excluding royalties
Total Cost/Mcf (Net)	$0.94	After royalties

Summary of Capital Costs $M	Projected Number	Average Cost	Total Cost
Drilling and Completion of Wells	5	$250	$1,250
Recompletion of Existing Wells	7	$ 25	$ 175
SGR Project Team Costs			$ 150
Total Costs			$1,575

*$M denotes thousands of dollars.

Case I: McFaddin "A" Lease (North McFaddin Field)

The remaining recoverable reserves were estimated for each of the thin-bed reservoirs as of January 1, 1992, prior to the transfer of operations to Anaqua Oil and Gas, Inc. The recoverable reserves of four wells completed by the operator since January 1992 are estimated, after risking, to be 2,396 Mmcf. The remaining undeveloped possible reserves are estimated, after risking, to be 4,060 Mmcf. The potential reserves are expected to be developed by recompletions in existing wells and by additional drilling.

The development plan involves the depletion of four wells currently completed in thin-bed reservoirs, the drilling and completion of one additional well, and recompletions in three existing wells. Eight wells are projected to have completions in the thin-bed reservoirs. Each of the eight wells is assumed to have a second completion after depletion of the first completion interval. Twelve successful completions are projected in future thin-bed development. The remaining undeveloped reserves of 4,060 Mmcf were allocated equally to each future successful completion (338 Mmcf per completion). The producing life of each completion was determined from an exponential decline from an initial rate of 500 mcf/d to a final rate of 50 mcf/d. Figure 48 shows the projected production from the current thin-bed completions and the upper curve shows the projected production that is anticipated from additional SGR development.

In this economic evaluation an effort has been made to account as fully as possible for costs and to take into consideration appropriate elements of risk in terms of the operating environment and resource recovery. The cost of developing the McFaddin thin-bed reservoirs is based on the performance of the existing four thin-bed completions, as well as costs incurred in the drilling and completion of 4 wells and in 16 completions after 1992. Capital costs are $1,450,000, which include drilling and completion costs ($1,000,000), recompletion costs ($300,000), and SGR project team costs ($150,000). The capital cost is determined to be $0.22 per mcf, and the total cost to develop and produce the reserves is $0.58 per mcf, excluding royalties (table 6). The total cost estimate includes capital costs, operating costs, and severance and ad valorem taxes and is calculated using

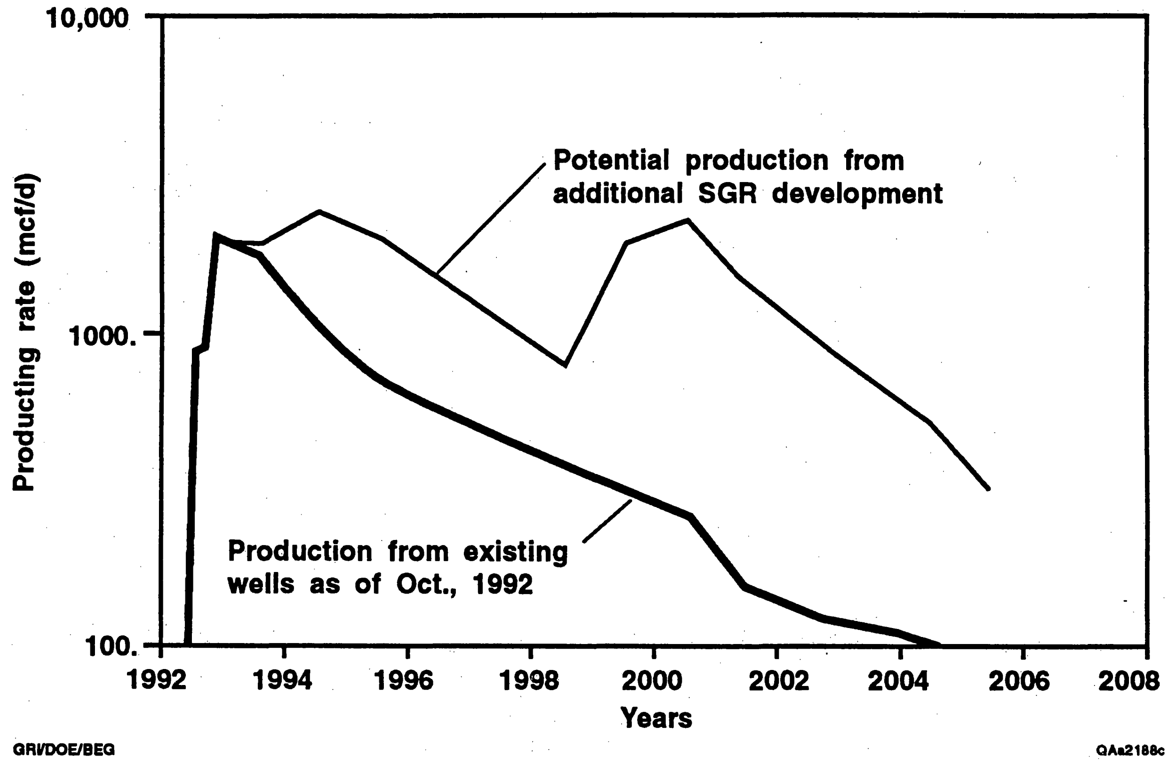


Figure 48. Case study I infield gas rate projections for 1992 through 2005. Production forecast for the thin-bed reservoirs. Lower curve represents projected production according to current thin-bed completions. Upper curve corresponds to anticipated projected production following development recommendations.

risked reserves. Because the production and development costs have been calculated on the basis of heavily risk-weighted reserves, the cost estimates are conservative. The corresponding cost estimates using unrisked reserves would be significantly less: $0.12 per mcf for capital costs and $0.31 per mcf for total costs.

Case II: H. W. Gee Lease (Agua Dulce Field)

The estimated reserves and economic analysis of the Gee lease development by the Pintas Creek Oil Company were current as of July 1991, when the company drilled and completed the Gee No. 6 well. The drilling of five wells was postulated in the economic assessment. The Pintas Creek Oil Company drilled three wells between July 1991 and October 1992. The drilling of two additional wells was projected. A total of 12 completions is anticipated from all five wells. Three wells (Gee Nos. 6, 7, and 8) have been drilled, and two additional wells are projected for these five wells. The risked undeveloped recoverable gas is estimated to be 2,386 Mmcf, and the risked developed recoverable gas is estimated to be 767 Mmcf, resulting in total risked reserves of 3,153 Mmcf (table 5). The remaining risked undeveloped reserves of 2,386 Mmcf were allocated equally to each future successful completion (265 Mmcf per completion). The producing life of each completion was determined from an exponential decline from an initial rate of 500 mcf/d to a final rate of 50 mcf/d. Each recompletion was timed immediately after depletion of the initial completion. The projected production from the current developed reserves and production that could result from additional SGR development are shown in figure 49.

Additional infield opportunities are identified by the SGR project analysis of the case I study area. Both recompletion opportunities and the potential reservoirs projected for contacting gas are listed in appendix 5. Based on the analysis of the 10 reservoirs considered in this study area, 2 potential infield wells—strategically placed within the center of the lease—would have the maximum opportunity to contact and recover additional gas resources.

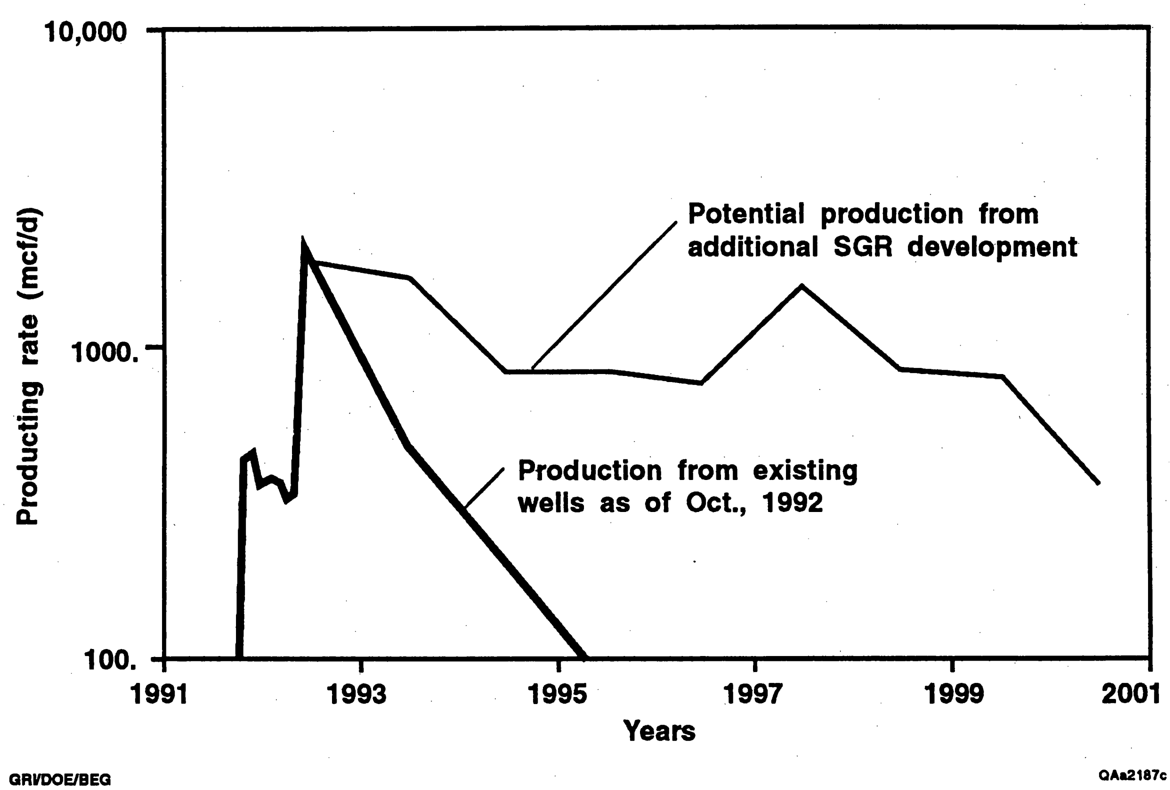


Figure 49. Case study II infield gas rate projections for 1991 through 2001. Lower curve represents projected production according to completions. Upper curve corresponds to anticipated projected production following development recommendations.

The capital costs are $1,575,000 and include drilling and completion costs ($1,250,000), recompletion costs ($175,000), and SGR project team costs ($150,000). The capital cost is determined to be $0.50 per mcf, and the total cost to develop and produce the reserves is determined to be $0.83 per mcf, excluding royalties. The total cost estimate includes capital costs, operating costs, and severance and ad valorem taxes and is calculated using risked reserves. Like the first case study, because the production and development costs have been calculated on the basis of heavily risk-weighted reserves, the cost estimates are conservative. The corresponding cost estimates using unrisked reserves would be significantly less: $0.30 per mcf for capital costs and $0.49 per mcf for total costs. The projected cumulative cashflow is shown in table 7 to be $2,911,000, after capital costs of $1,575,000. The cumulative cashflow has a present worth of $1,636,000, after discounting at 10 percent, and $1,933,000, after discounting at 7 percent.

CONCLUSIONS

This study documented the application of SGR concepts and technologies by independent gas operators by using economic evaluations of two mature gas fields. These evaluations were undertaken to demonstrate the feasibility of converting technically recoverable resources into economically producible reserves. The SGR project, in cooperation with operator-initiated reexploration in two separate mature onshore fields, used integrated geologic, engineering, and petrophysical analyses of 21 reservoirs to define 9.6 Bcf of economically recoverable risk-weighted gas reserves from an original gas in place of 36.9 Bcf. More than one-third (3.2 Bcf) of these gas reserves have been developed since mid-1991. From mid-1991 to November 1, 1992, 677 Mmcf has been produced; the remaining gas to be produced over the next 10 yr is projected to be 2.49 Bcf.

In the case I study area in North McFaddin field, the total cost to develop and produce SGR reserves of 6.5 Bcf is projected at $0.58 per mcf, excluding royalties. In the case II study area in Agua Dulce field, the total cost to develop and produce SGR reserves of 3.2 Bcf is projected at $0.83 per mcf, excluding royalties. In both case studies the production and development costs have been calculated on the basis of heavily risk-weighted reserves and are therefore conservative. The corresponding total cost estimates calculated with unrisked reserves for case I and case II would be $0.31 per mcf and $0.49 per mcf, respectively.

In both case studies, the identification of thin-bypassed reservoirs has resulted in additional gas production. Application of the new generation of logging tools, such as the high-resolution induction array log, in these mature fields (where only old electrical logs or induction were available in the past) is important in identifying potential SGR resources today. Similarly, in both case studies most of the thin beds identified are depletion-drive mechanisms. Therefore, knowledge of accurate reservoir pressures—either by open-hole pressure tests or postcompletion measurement—is important for subsequent development of the field.

Although both study areas have similar reservoir-drive mechanisms, equivalent drilling costs for additional wells, and comparable postcompletion operating costs, their differing geologic factors, including differences in structural and diagenetic overprint, will affect the reservoir compartment size differently, which in turn affects the economics of infield development. Specifically, in the case II study area, where the reservoir compartments are smaller, more wells and recompletions are required to maximize the SGR resource.

In the case I study area, identification of thin-bed reservoirs is critical as a strategy to maximize the recovery of incremental gas. Individual reservoirs, typically no more than 10 ft thick, comprise heterolithic lithosomes of somewhat irregular, sheetlike external geometry; these reservoirs consist of a series of thin, but highly permeable, sandstones. An individual well may contain several of these potential reservoir sandstones. The static reservoir pressure of these thin-bed sandstone intervals can be near the original pressure at completion. An individual well may contain several of these potential reservoir sandstones. Analysis of production and flowing pressure data by the SGR project has allowed estimates of productivity and drainage volumes in these thin-sandstones reservoirs. A radial-flow simulator, used to estimate the drainage volumes and kh on the basis of daily production and flowing pressures, determined that the initial gas in place for each of these thin-sandstone completions is from 0.4 to 1.0 Bcf. Using a net pay thickness of 4 ft, equivalent drainage areas of 100 to 300 acres were determined. The effective kh was estimated at approximately 50 md-ft. Reservoir units were interpreted to reflect the distal deposits of successive storm events in a barrier/strandplain depositional setting. Engineering data support the contention that these reservoirs are characterized by depletion-drive mechanisms. These thin sandstones were bypassed because they are difficult to resolve on old electric logs and may have been considered as uneconomical to develop. The array induction resistivity log was compared with the enhanced phasor induction log. Results indicate that the array induction log is a superior tool for resolving thin beds. With the array induction log, beds that are 2 ft thick can easily be found. This new open-hole resistivity tool identifies these secondary gas resources in sandstone thin beds.

To maximize the recovery of incremental gas in the case II study area, the well spacing in the Gee lease may need to be decreased. The final analysis of well tests performed by the SGR project and the operator indicates a similar producibility pattern across the Gee lease and at each of the reservoir horizons. Reservoir producibility is affected by multiple barriers, which are evident in each of the four wells tested. Analysis of pressure-buildup profiles from each of these wells can be matched with the expected profile for a long and narrow reservoir shape. The strong linear-flow behavior of the wells tested hinders satisfactory analyses of permeability and pressure using conventional Horner and radial-type curve methods. Thus, it is difficult for the operator to assess completion efficiency and recoverable reserves from a completion after only a short production history and short-duration buildup test. The width of these drainage shapes varies from 150 to 2,000 ft. These drainage shapes indicate that there is probably a strong structural overprint caused by faulting and that this faulting is probably more complex than can be mapped from well control. The linear flow geometry caused by a series of parallel faults has special implications for field development. Test analysis using linear-flow methods can be used to suggest an appropriate well spacing dependent on width and other formation parameters. Identification of linear trends may justify closer well spacing in the direction perpendicular to fault trends and parallel to channel sands that are the primary reservoir facies. This may reflect the case on the Gee lease, where an SGR strategy of decreased well spacing may be needed to effectively drain the reservoir compartments that have a general northwest-to-southeast orientation of channel sands and a probable northeast-to-southwest fault pattern. The potential impact of a 3-D seismic log as another tool to decrease infield costs by targeting reservoir horizons should also be considered as a secondary gas recovery strategy.

The analyses presented in this report document two examples of the benefits of the SGR approach to developing gas resources and demonstrate that small independent operators can economically convert technically recoverable resources into developed reserves. The SGR project is providing an important contribution to the development of future United States' domestic gas supply by working with independent producers to identify and demonstrate the benefits of low-cost strategies to incrementally recover natural gas from known fields.

The results of this study make it clear that it is technically feasible and profitable for small operators to search for and recover secondary gas resources. Through the use of SGR technology and concepts, independent producers can identify and target specific wells for the application of current technology to provide a low-cost method to maximize the economic recovery of the gas resource. The technology is being used by independent producers in the field. The SGR project provides an interdisciplinary approach to the use of that technology to maximize the recovery of the resource and minimize the costs of development. The value of the approach was highlighted by David Coover, Jr., President of Pintas Creek Oil Company (personal communication, 1992) when he stated:

> With the exodus of major companies from the domestic gas exploration business, independents, none of which have the resources available to conduct the level of research being generated by the Gas Research Institute, will be ever more dependent on industry supported research to stay in business. The economics of this business have become too critical to leave infield exploration as a game of chance in which the number of wells compensates for unfocused exploration and production practices. Both the concepts and analytical tools being tested by this project will be essential to the survival of independent operators in the domestic gas industry.

Although the SGR project has focused on the Texas Gulf Coast onshore since the project was initiated 4 yr ago, industry officials familiar with the project have indicated a strong interest in additional research for reservoir compartmentalization in the Midcontinent. These two case studies from the Texas Gulf Coast are representative of the possible application of the SGR approach in developing secondary gas reserves in mature fields in other regions of the lower 48 states. In effect, the SGR project is leading by example by working directly with independent operators.

By providing producers with a low-cost strategy to maximize the economic recovery of gas from mature fields, the SGR project can make a valuable contribution to the development of a significant portion of the conventional natural gas in existing fields. Thus, the benefits of the research funded by the Gas Research Institute and the U.S. Department of Energy are providing technology transfer to independent producers, facilitating the use of low-cost strategies to develop incremental reserves of domestic natural gas, and providing a low-cost source of gas supply for U.S. consumers.

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APPENDIX 1: Formula for Determination of Original Gas in Place

The original gas in place (OGIP) was computed from the following formula:

$$OGIP = 43.56\ (h)\ (a)\ (phi)\ (1-Sw)\ (Bgi)\ (mcf)$$

where OGIP = original gas in place, 43.56 = unit conversion factor (mcf/acre-ft), h = net pay thickness (ft), a = area (acres), phi = porosity (fraction), Sw = water saturation (fraction), Bgi = initial gas volume factor (standard cubic ft/reservoir cubic ft), and mcf = 1,000 standard cubic ft.

APPENDIX 2: Case I Additional Reservoirs

4,200-Ft Zone (No.1 Reservoir)—Depleted

Of the thin-bed units under investigation, this reservoir has experienced the greatest previous development, with completions in six wells. A cumulative gas production of 4,360 Mmcf was reported from 1954 through 1969. Available pressure, completion, and production data suggest that this reservoir was characterized by a strong water-drive mechanism. OGIP under the North McFaddin "A" lease is estimated at 7,193 Mmcf from an average thickness of 9.2 ft and an original reservoir pressure of 1,797 psi.

Log analysis determined that strong water-drive reservoirs in North McFaddin (for example, Sinton Sandstone) were characterized by residual trapped-gas saturation of approximately 30 percent. Hence, a reduction in gas saturation from 55 percent to 30 percent by water drive indicates a recovery factor of 45 percent. A reported cumulative production of 4,360 Mmcf represents a 52-percent recovery of estimated OGIP. If the reservoir has experienced water encroachment by water-drive mechanisms, it is unlikely that any potential for additional reserve recovery remains.

4,200-Ft Zone (No. 6 Reservoir)—Bypassed

To date, this thin-bed unit has no previously reported production or completion attempts and remains potentially bypassed. Formation evaluation confirms it as a potentially productive zone in well A-60 at depths of 4,252 to 4,254 ft. Although the correlative zone is present elsewhere in North McFaddin field, with the exception of well A-60, it is characterized ubiquitously by pessimistic well-log parameters, and it is not possible to identify potentially productive areas beyond the A-60 well. A wireline pressure test of 1,790 psi in well A-60 confirms the original pressure. The potentially productive limits of this reservoir may be localized in extent, and related to possible fault compartmentalization within the southernmost portion of the field. The potentially productive extent of this reservoir is estimated to be about 80 acres, based on the average distance (1,000 ft) to adjacent offset wells. A volumetric assessment of the potential resource indicates 122 Mmcf OGIP.

4,800-Ft Zone (No. 1 Reservoir)—Incompletely Drained

Superimposed well-log parameter maps indicate that this zone is effectively partitioned into two noncommunicating compartments. Compartmentalization is controlled by a northeast-southwest-trending stratigraphic termination through the central portion of the field. Potential OGIP for both compartments is estimated at 2,378 Mmcf. It is believed that the southern compartment is incompletely drained and the northern compartment is bypassed. However, further resource development is possible in both reservoir compartments.

The southern compartment produced 521 Mmcf in well A-18 from 1962 through 1971. Sidewall core data in structurally higher wells A-28 and A-4 indicate potential gas production. Wells A-4 and A-28 are no longer available for completion in this reservoir. A-4 was plugged and abandoned in June 1979, and A-28 is currently a brine-disposal well at a depth of 4,470 ft. Superimposed well-log parameter maps indicate the potential productivity of this zone in a proposed development well midway between A-4 and A-17.

No production or completions have been reported for the northern reservoir compartment. On the basis of contoured well-log parameter maps, it is proposed that this reservoir compartment could be developed by completing the zone in wells A-8 or A-24.

4,800-Ft Zone (No. 5 Reservoir)—Depleted

A cumulative gas production of 341 Mmcf was reported in well A-24 in the 4,800-ft zone (No. 5 reservoir) from 1979 to 1985. Well records indicate that the zone was abandoned in January 1985, following water production. The mapped potentially productive area of the zone is estimated at 120 acres, with an average thickness of 8.3 ft. Volumetric estimates indicate

697 Mmcf OGIP. Recoverable gas in place estimates of 340 Mmcf and cumulative gas production of 341 Mmcf indicate that this zone has probably been depleted of recoverable gas. Petrophysical analyses indicate that the zone is water saturated in wells A-59 and A-60.

4,800-Ft Zone (No. 7 Reservoir)—Bypassed

The 4,800-ft zone has not been previously developed. The potentially productive extent of this unit was estimated at 539 acres, with an average thickness of 3.2 ft. An OGIP of 1,221 Mmcf and potentially recoverable reserves of 976 Mmcf were estimated from volumetric calculations.

Superposed structural and well-log parameter maps delineate well A-59 as a prospective candidate to exploit this potential resource. A wireline pressure test, recording 2,073 psi from this zone in well A-59 in November 1992, confirms the original reservoir pressure. In addition, log analysis indicates gas potential. Superposed well-log parameters also indicate production potential in the vicinity of well A-4; it is anticipated that this zone would form an important completion candidate in the proposed development well midway between A-4 and A-17.

4,800-Ft Zone (No. 8 Reservoir)—Incompletely Drained

The 4,800-ft zone was bypassed during primary field development. The potentially productive areal extent of this unit was estimated at 1,027 acres, with an average thickness of 2.6 ft. A volumetric assessment of the potential resource indicates 1895 Mmcf OGIP and 1,516 Mmcf potential recoverable gas. Since its acquisition of the North McFaddin field lease, Anaqua Oil and Gas has reentered the previously shut-in gas well A-7 and in August 1992 completed this zone at a depth of 4,896 to 4,906 ft. The reservoir was completed without stimulation treatment. The peak production rate was 1,305 mcf/d, with a flowing well-head pressure of 1,490 psi. The initial wellhead shut-in pressure recorded 1,765 psi, corresponding to a minimum bottomhole pressure of 2,019 psi, indicating original reservoir pressure when the zone was completed in the A-7 well. Cumulative gas production to November 1, 1992, was 79 Mmcf.

By evaluating the short-term production history of the completion in well A-7 with the aid of a radial-flow simulator, 406 Mmcf OGIP and 18-md permeability provided the closest match to the production and pressure data. Using an average thickness value of 2.6 ft, the drainage area for this completion is estimated at approximately 185 acres. An additional 1,200 Mmcf could be recovered by additional completions in this reservoir interval.

Superposed well-log parameter maps, integrated with a structure-contour map, delineated additional completion opportunities in wells A-28 and A-40. The reservoir in the A-40 well, at depths of 4,940 to 4,944 ft, is characterized by good resistivity despite its structurally unfavorable setting. A successful completion in the A-40 well could expand the currently interpreted productive limits of this reservoir. The A-28 is currently a brine-disposal well at 4,470 ft depth and is no longer available for completion in this reservoir. Given the favorable character of well-log parameters in the vicinity of well A-4, this zone is expected to be an important potential recompletion candidate in the proposed development well midway between A-4 and A-17.

4,800-Ft Zone (No. 9 Reservoir)—Bypassed

The No. 9 reservoir in the 4,800-ft zone is bypassed and undeveloped. The mapped potentially productive area of this zone is 482 acres, with an average thickness of 2.1 ft and an estimated OGIP volume of 728 Mmcf. The potential recoverable resource is estimated at 583 Mmcf.

Superposed structural and well-log parameter maps confirm the favorable position of well A-23 to exploit this bypassed resource; they also indicate completion opportunities within the correlative zone in wells A-24 and A-28. However, neither the A-28 well, currently a brine-disposal well, nor the A-23 well, plugged and abandoned in 1979, are available for completion in this zone. Thus, it is recommended that this zone be completed in well A-24. Sidewall core data in well A-24, indicating potential gas production, support this recommendation. Given the close proximity of well A-28, this zone would be an excellent completion target in the proposed development well midway between A-4 and A-17.

4,800-Ft Zone (No. 11 Reservoir)—Incompletely Drained

The No. 11 reservoir in the 4,800-ft zone was completed during the primary field development and produced 1,911 Mmcf cumulative gas from 1964 through 1980. The well A-8 completion, at a depth of 4,996 to 5,002 ft, produced 1,800 Mmcf from 1963 to 1973; the well A-30 completion, at a depth of 4,998 to 5,008 ft, produced 111 Mmcf from 1972 to 1980.

The mapped potentially productive areal extent of this reservoir in North McFaddin was determined to be 339 acres, with an average thickness of 4.5 ft, and provided an initial volumetric estimate of OGIP of 1,300 Mmcf. However, this estimate of OGIP is less than cumulative gas production to date (1,911 Mmcf), which implies that the productive area of this reservoir is greater than the area mapped. An additional productive area of this reservoir probably lies outside of the North McFaddin lease.

Following shut-in of the A-8 well, an initial wellhead shut-in pressure of 713 psi was reported for the A-30 well in 1972. This initial wellhead shut-in pressure corresponds to a static bottomhole pressure of about 800 psi. By performing a material-balance calculation using pressure and production data, OGIP was estimated to be as much as 2,763 Mmcf. Using this revised estimate of OGIP, a drainage area of 850 acres was calculated for the completion in well A-30.

Since its acquisition of North McFaddin field, Anaqua Oil and Gas has restored production from this zone in the previously shut-in gas well A-8. Gas production resumed October 1, 1992, with production of 3 Mmcf to November 1, 1992. Current wellhead shut-in pressure and deliverability are not known. A potential recoverable gas volume of 2,211 Mmcf and a cumulative gas production of 1,911 Mmcf suggest that the reservoir is approaching depletion and that production of the remaining potential reserves may be achieved by the A-8 well. The remaining reserve potential, however, could be more effectively assessed if a shut-in pressure test and deliverability test were performed on the A-8 well.

If the reservoir pressure is sufficiently high but the deliverability of the A-8 well is poor, an additional well to develop and exploit this resource would be A-59. Sidewall cores from the equivalent zone in well A-33 indicated potential gas, and also support the recommendation to develop A-33.

APPENDIX 3: Case I: Production by Well and Reservoir

Miocene Pay Zones (Oakville Formation)

3,200-Ft Reservoir

Well	Dates of production		Cumulative production (Mmcf)
A-16	1961–1976		991
		Total	991

3,500-Ft Reservoir

Well	Dates of production		Cumulative production (Mmcf)
A-16	1963–1976		417
A-32	1964–1968		394
		Total	811

Catahoula Stringer (3,700-Ft Reservoir)

Well	Dates of production		Cumulative production (Mmcf)
A-16	1963–1976		939
		Total	939

Catahoula Sandstone (3,800-Ft Reservoir)

Well	Dates of production		Cumulative production (Mmcf)
A-1	1954–1966		762
A-2	1954–1963		827
A-6	1957–1972		1,347
A-16	1976–1988		452
A-32	1972–1988		246
		Total	3,634

4,200-Ft Sandstone Series (4,200-Ft Reservoirs)

Well	Dates of production		Cumulative production (Mmcf)
A-1	1954–1966		2,201
A-2	1954–1963		1,147
A-6	1957–1961		575
A-21	1962–?		424
A-32	1968–1972		69
		Total	4,416

Oligocene Pay Zones (Frio Formation)

Greta Stringer (4,500-Ft Reservoirs)

Well	Dates of production		Cumulative production (Mmcf)
A-2	1932–1944		7,000 (?)
A-1	1937–1944		3,400 (?)
A-4	1938–1949		3,027
A-7	1945–1963		2,133
A-16	1961–1963		251
		Total	15,811

4,800-Ft Sandstone Series (4,800-Ft Reservoirs)

Well	Dates of production	Cumulative production (Mmcf)
A-18	1962–1971	521
A-24	1979–?	335
A-22	1963–1981	48
A-30	1972–?	112
A-8	1964–1973	1,800
	Total	2,816

Sinton Sandstone (5,200-Ft Reservoir)

Well	Dates of production	Cumulative production (Mmcf)
A-3	1934–1967	12,803
A-5	1942–1961	26,419
A-6	1944–1957	8,327
A-10	1948–1963	14,698
A-4	1950–1967	8,937
A-15	1956–1971	10,061
A-8	1962–1973	3,646
A-21	1962–1966	740
A-24	1966–1979	1,973
A-36	1966–1974	2,105
A-23	1972–1974	138
	Total	89,847

5,300-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-8	1962–1973	3,116
A-20	1962–1979	<1
	Total	3,116

5,350-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-7	1972–?	55
A-8	1973–?	1,395
	Total	1,450

5,400-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-25	1982–?	15
	Total	15

5,675-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-42	1973–1976	42
	Total	42

5,725-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-21	1967–1972	7
	Total	7

5,750-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-18	1962–1971	375
	Total	375

5,800-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-5	1957–1961	85
	Total	85

5,850-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-42	1973–1976	16
	Total	16

6,050-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-40	1980–?	47
	Total	47

6,100-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-28	1963–?	16
A-25	1964–?	260
A-26	1964–1972	8
A-40	1973–1974	57
A-42	1973–1974	52
	Total	393

6,150-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-14	1956–1971	538
	Total	538

6,250-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-41	1977–1980	89
	Total	89

6,700-Ft Reservoir

Well	Dates of production	Cumulative production (Mmcf)
A-41	1973–1974	72
	Total	72

APPENDIX 4: Case II: Production by Well and Reservoir

PINTAS CREEK

Well no.		Reservoir	U perf.	L perf.	Cum. gas (mcf)	FP (date)	LP (date)	Status
1		BENTONVILLE	4,610	4,625	4,164,570	5010	9209	S/I
2	C	BENTONVILLE	4,612	4,662	2,640,499	5210	6610	S/I
2	T	COMSTOCK UPPER	4,759	4,775	147,688	5210	N/A	P&A
2		5,300-ft	5,334	5,352	813,728	7103	7912	P&A
2		6,675-ft	6,659	6,674	213,064	6612	7009	P&A
3		COMSTOCK UPPER	4,745	4,760	2,156,729	5210	N/A	P&A
3		4,950-ft	4,976	4,981	57,978	6402	N/A	P&A
4	F	4,500-ft	4,426	4,434	46,192	9205	9207	ACT
4	H	5,350-ft	5,346	5,351	9,032	9204	9207	ACT
4	D	5,450-ft	5,415	5,518	932,025	7610	9209	ACT
4	H	INGRAM	5,712	5,727	722,922	7608	9203	ACT
4	F	6,100-ft	6,064	6,080	1,096,632	7608	9204	ACT
4	L	DABNEY	6,576	6,581	1,537	7608	7608	P&A
5	F	5,300-ft	5,273	5,288	56,074	9204	9209	ACT
5	F	5,450-ft	5,470	5,491	145,453	7708	9203	ACT
5	D	INGRAM	5,738	5,747	539,075	7708	9209	ACT
					13,743,198			

APPENDIX 5: SGR Completion Opportunities: Case I and Case II

Case I: McFaddin 'A' Lease
North McFaddin Field

Reservoir/ Zone	Reservoir Terminology	Reservoir Completed in Well No.	Opportunity in Well No.
3700	Incompletely drained	16	59, 60, 61*
4200 No. 1	Depleted	1, 2, 6, 16, 21, 32	None identified
4200 No. 5	Bypassed	58	59, 60, 61*
4200 No. 6	Bypassed	None	60
4800 No. 1	Incompletely drained	18	8, 24, 61*
4800 No. 2	Untapped	None	24, 29, 59, 60
4800 No. 5	Depleted	24	None identified
4800 No. 7	Bypassed	None	59, 61*
4800 No. 8	Incompletely drained	7	40, 61*
4800 No. 9	Bypassed	23	24, 61*
4800 No. 11	Incompletely drained	8, 30	59
			*Future well

Case II: Completion Opportunities
Gee lease
Agua Dulce Field

Reservoir	Reservoir Terminology	Reservoir Completed in Well No.	Opportunity Well No.
4420'	Bypassed	4, 7	
4700'	Incompletely drained		6, 10*
5200'	Incompletely drained		6, 8, 9*
5300'	Incompletely drained	6	9, 10*
5400'	Untapped		8, 9*
5450'	Untapped		8, 9*
6050'	Bypassed		8, 9*
6300'	Bypassed		8, 9*
6500'	Incompletely drained	8	9*
6550'	Untapped	8	9*
			*Future well