FOSSIL ENERGY

TARGETED TECHNOLOGY APPLICATIONS FOR INFIELD RESERVE GROWTH: A SYNOPSIS OF THE SECONDARY NATURAL GAS RECOVERY PROJECT RESEARCH, GULF COAST BASIN

Final Report

Reporting Period: September 6, 1988–April 30, 1993

Prepared by
Raymond A. Levey

Principal Investigators
Robert J. Finley, Raymond A. Levey, and Bob A. Hardage

Researchers
W. A. Ambrose, J. R. Ballard, M. A. Burn, R. E. Collins, R. J. Finley, J. D. Grigsby, E. H. Guevara, J. D. Hall, B. A. Hardage, W. E. Howard, T. L. Hower, L. A. Jirik, D. R. Kerr, M. E. Kocberber, R. P. Langford, R. A. Levey, M. E. Lord, C. L. Ruthven, M. A. Sippel, J. M. Vidal, E. G. Wermund, and S. G. Zinke

January 1994

Work performed under DOE contract no. DE-FG21-88MC25031
and GRI contract no. GRI-5088-21-1718

for
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, WV 26507-0880

by
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EXECUTIVE SUMMARY

A diverse and vast resource base of 1,295 trillion cubic feet (Tcf) of technically recoverable natural gas resources (including proved reserves, conventional resources, and nonconventional resources) was estimated by the National Petroleum Council (1992) in a recent analysis of domestic petroleum supplies. Of this resource base, 216 Tcf is predicted to be recoverable by reserve appreciation in existing fields in the lower 48 states. The integrated application of concepts and cost-effective technologies from the disciplines of geology, engineering, geophysics, and petrophysics will be required for converting these resources into producible reserves.

In the last decade, characterization of the internal geometry of reservoirs, mainly oil reservoirs, has demonstrated a higher degree of compartmentalization than previously recognized. This compartmentalization, other than structural compartmentalization, is primarily a function of the depositional system and, secondarily, of the diagenetic history of the reservoir after deposition. The objective of a current infield reserve growth analysis of nonassociated natural gas reservoirs is to define the potential for incremental gas recovery based on better understanding of depositional and diagenetic heterogeneity within these reservoirs. Natural gas reserve growth (reserve appreciation) in conventional reservoirs has multiple components. Historically, extensions and deeper pool drilling have been the standard approach used by industry to achieve infield reserve additions. Recompletions of existing wells were often made without the concepts of reservoir heterogeneity or compartmentalization as a tool in recompletion strategy. Where significant geologic variation occurs, untapped, incompletely drained, or bypassed reservoir compartments remain to be drained of natural gas by new infield drilling or by recompleting strategically placed development wells. Today infield reserve growth is beginning to be based on an understanding of vertical and lateral heterogeneity that leads to recompletions in bypassed and incompletely drained reservoirs that were not previously recognized. In addition to concepts of reservoir heterogeneity and compartmentalization, new surface and downhole tools are being developed that will enhance the operator's ability to define these resource targets with greater precision and reliability. Examples of these tools now being developed and selectively used include borehole gravity, through-casing resistivity, cross well geophysics, and surface three-dimensional seismic in the onshore.

In the lower 48 states during the past 6 years, an increasing trend is re-exploration and redevelopment in large known fields with an existing infrastructure. The viability of this trend has important implications for our future domestic gas supply as both major integrated companies and independents seek to recover the substantial remaining gas resources identified in the 1992 resource assessment completed by the National Petroleum Council (1992).

Fifty percent of the cumulative natural gas production in Texas is derived from siliciclastic reservoirs in existing fields. Evaluation of gas resources in sandstone reservoirs is part of a continuing research initiative at the Bureau of Economic Geology focusing on strategies to maximize the producibility of the natural gas resource base in the lower 48 states.

The *Secondary Natural Gas Recovery (SGR): Targeted Technology Applications for Infield Reserve Growth* is a joint venture research project sponsored by the Gas Research Institute (GRI), the U.S. Department of Energy (DOE), the State of Texas through the Bureau of Economic Geology at The University of Texas at Austin, with the cofunding and cooperation of the natural gas industry. The SGR project is a field-based program using an integrated multidisciplinary approach that integrates geology, geophysics, engineering, and petrophysics. A major objective of this research project is to develop, test, and verify those technologies and methodologies that have near- to mid-term potential for maximizing recovery of gas from conventional reservoirs in known fields. Natural gas reservoirs in the Gulf Coast Basin are targeted as data-rich, field-based models for evaluating infield development.

The SGR research program focuses on sandstone-dominated reservoirs in fluvial-deltaic plays within the onshore Gulf Coast Basin of Texas (fig. 1). The primary project research objectives are:

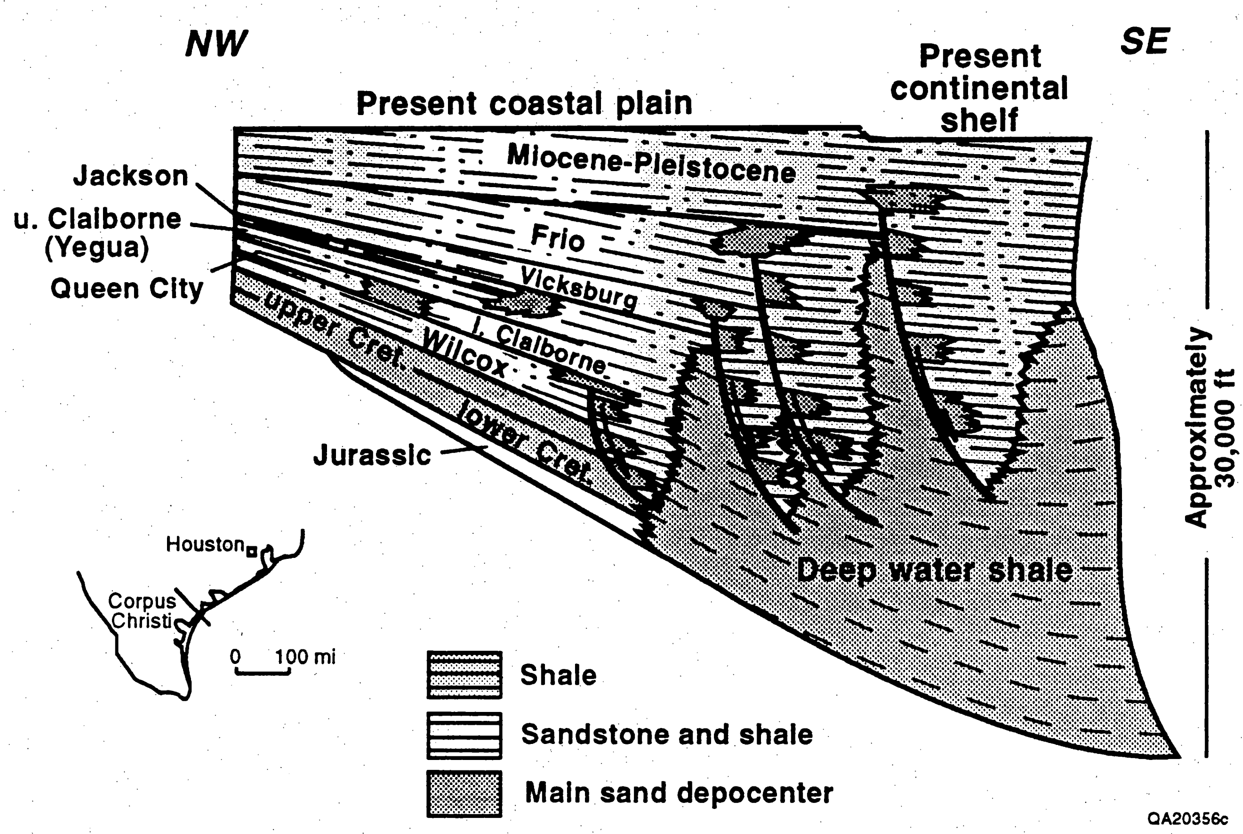
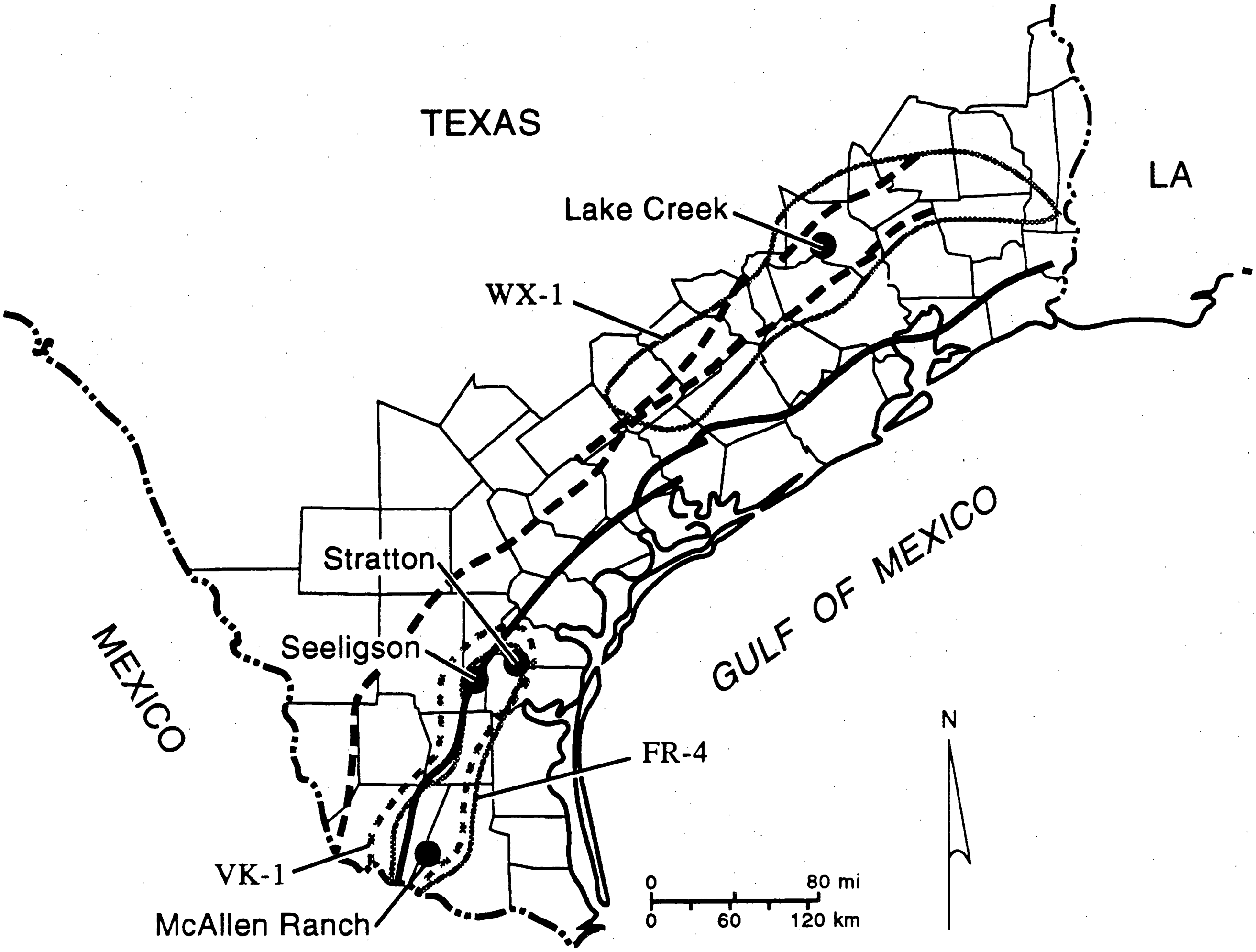


Figure 1. Schematic depositional dip-oriented cross section through the central Texas Gulf Coast Basin, illustrating the relative position of major sand depocenters (after Bebout and others, 1982).

- To establish how depositional and diagenetic heterogeneities cause, even in reservoirs of conventional permeability, reservoir compartmentalization and hence incomplete recovery of natural gas
- To document examples of reserve growth occurrence and potential from fluvial and deltaic sandstones of the Texas Gulf Coast Basin as a natural laboratory for developing concepts and testing applications
- To demonstrate how the integration of geology, reservoir engineering, geophysics, and well log analysis/petrophysics leads to strategic recompletion and well placement opportunities for reserve growth in mature fields.

Geologic and engineering screening of 14 major gas fields in the onshore Gulf Coast Basin indicated that leading candidate gas fields in southeast, south-central, and South Texas include Lake Creek, Seeligson, Stratton-Agua Dulce, and McAllen Ranch fields (fig. 2). The fields were selected by applying a methodology developed by the project for the geological and engineering screening of sandstone reservoirs (Finley and others, 1990). Geologic and engineering analyses of publicly available and industry-supplied data helped to define those gas fields that were suitable as a natural laboratory for project research. Screening of heterogeneous fluvial-deltaic reservoirs of South Texas defined the first areas of field data collection and formed a major part of early phases of the project. Producing intervals are fluvial reservoirs in the Frio Formation (Seeligson and Stratton-Agua Dulce fields) and deltaic reservoirs in the Wilcox (in Lake Creek field) and in the Vicksburg (in McAllen Ranch field). Results obtained from the initial project phase formed the basis for technical presentations to industry representatives and stressed the potential benefits of cooperating with the Secondary Gas Recovery project. These presentations led to cooperative studies in four Gulf Coast fields.

Cooperative data analyses were initiated with Shell Western Exploration and Production Inc. (SWEPI) in 1989 at McAllen Ranch field in South Texas, which is part of the gas play known as Vicksburg Deltaic Sandstone in the Rio Grande Embayment (VK-1) (Kosters and



TREND	PLAY	FIELD
FRIO	FR-4	Stratton/Seeligson
VICKSBURG	VK-1	McAllen Ranch
WILCOX	WX-1	Lake Creek

Wilcox fault zone

Vicksburg fault zone

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Figure 2. Lithologic distribution of gas production from major Texas gas reservoirs and location map illustrating the boundaries of the three major gas plays and fields being investigated by the Secondary Natural Gas Recovery project (modified from Kosters and others, 1989).

others, 1989). Research results for these fluvial to wave-modified deltaic deposits were described by Langford and others (1992a).

In 1990 and 1991, cooperative data were obtained from Mobil Exploration and Producing U.S., Inc., in Lake Creek field, which is part of the Wilcox Deltaic Sandstone in the Houston Embayment (WX-1) (Kosters and others, 1989). Project research focused on integrating geologic, engineering, and formation evaluation of fluvial-dominated deltaic deposits in the lower Wilcox group (Grigsby and others, 1992).

Both Stratton and Seeligson fields were candidates for detailed investigations within the Frio Fluvial-Deltaic Sandstones along the Vicksburg Fault Zone gas play (FR-4) (Kosters and others, 1989; Finley and others, 1990). Seeligson field was the first SGR research field study site in the Frio Formation. Starting in mid-1990, with the cooperation of Union Pacific Resources Corporation, the SGR project focused its research efforts on quantifying secondary gas resources in middle Frio gas reservoirs in Stratton field in Nueces, Kleberg, and Jim Wells Counties, Texas (Levey and others, 1993a).

In 1992 and 1993, an assessment of technical applications and economic feasibility of SGR approaches in small-scale application (mini-evaluations) were conducted to track the benefits and results. In cooperation with independent gas producers, an analysis of the development and operations to find and produce secondary gas reserves was evaluated in two separate field areas (Levey and others, 1993b).

Results from the multiyear cross-disciplinary analysis of fluvial-deltaic reservoir systems conducted by the Bureau on behalf of DOE and GRI indicate that:

- Significant natural gas reserve appreciation opportunities exist where reservoirs are heterogeneous and compartmentalized
- Such compartmentalization, other than structural, is depositional and/or diagenetic in origin and can be defined through a geologically centered approach to understanding reservoir flow units

- Concept-driven integration of the four fundamental geoscientific disciplines (geology, engineering, geophysics, and formation evaluation) is crucial to recognizing and exploiting reserve growth opportunities
- Although absolute rules on flow communication between facies are not apparent, as the size of the reservoir compartment decreases, stratigraphic variability often increases and secondary compartments are often encountered in the smaller size class reservoirs
- The application of SGR approaches in two mini-evaluations conducted with the cooperation of independent operators documented development costs in the range of \$0.60 to \$0.80/Mcf for incremental reserve appreciation.

INTRODUCTION

This is the final report and a summary of work for DOE contract number DE-FG21-88MC25031 titled "Secondary Natural Gas Recovery: Targeted Technology Applications for Infield Reserve Growth." This report constitutes the final report for the period September 1988 through April 30, 1993, and provides an accounting of the total work performed and dissemination of information by the project between September 1988 and December 31, 1993.

Objective of this Report

A listing of project technical reports in the form of topical reports, articles in technical journals, abstracts, conference proceedings, lectures and public addresses, short courses and workshops presenting the results from the SGR project provides a technical accounting of the extensive work performed on this project.

Key results from this multiyear research program are presented in the form of expanded annotated research summaries for topical reports prepared for GRI and an annotated summary of technical articles. Additional technology transfer efforts include a listing of the titles from project abstracts, lectures and public addresses, project short courses and core workshops presented on behalf of DOE and GRI, and multiple half-day presentations conducted on behalf of the Texas Independent Producers and Royalty Owners, GRI, and the Bureau. Combined short courses, workshops, and half-day presentations were attended by over 900 participants between 1991 and 1994. The appendices of this report contain the complete reprints of four SGR articles prepared for the DOE conference proceedings for the Morgantown Energy Technology Center (METC).

Definition of Secondary Natural Gas

"Secondary natural gas resource" refers to that segment of in-place gas that is typically not produced during historical approaches to development of a field containing mostly conventional permeability reservoirs. Secondary natural gas is the incremental gas that is recoverable using currently available production methods in mature fields in conventional reservoirs. Reserve growth of the non-associated gas resources examined by the SGR project consists of gas that has been either uncontacted, bypassed, or incompletely drained at current field spacing. It is not gas produced from existing completions through mechanisms such as water or carbon dioxide injection. When new wells are drilled or wells are recompleted within a given field or reservoir, the rate of gas production increases. A production increase does not always mean that reserves have been increased because the reserves tapped by existing wells may be shared with the new wells and therefore produced more quickly. Where new wells or recompletions tap entirely new reservoirs or portions of reservoirs, production from these settings is undeniably a reserve increment. Where new completions are made within or adjacent to existing production, the situation is less clear. In these cases, the cumulative production of the old and new completions must be estimated to prove a reserve increment.

Development wells can be categorized as either infield or infill wells. Infield wells are commonly exploratory in nature and are often targeted to deeper pool objectives. Infield wells are within the established field boundary but are often irregularly spaced. Infill wells are often spaced at half or some variant of the established regulatory well pattern. Infill wells are targeted with the objective of increased or accelerated recovery from a previously known productive reservoir. Infield wells may be closer to previous wells than the established spacing either specified by field rules or typically utilized for that class of reservoirs.

Reservoir Compartment Terminology

Within a mature field, besides currently producing and depleted reservoirs, five additional categories are useful for evaluating infield reserve growth potential (fig. 3): (1) *New infield*

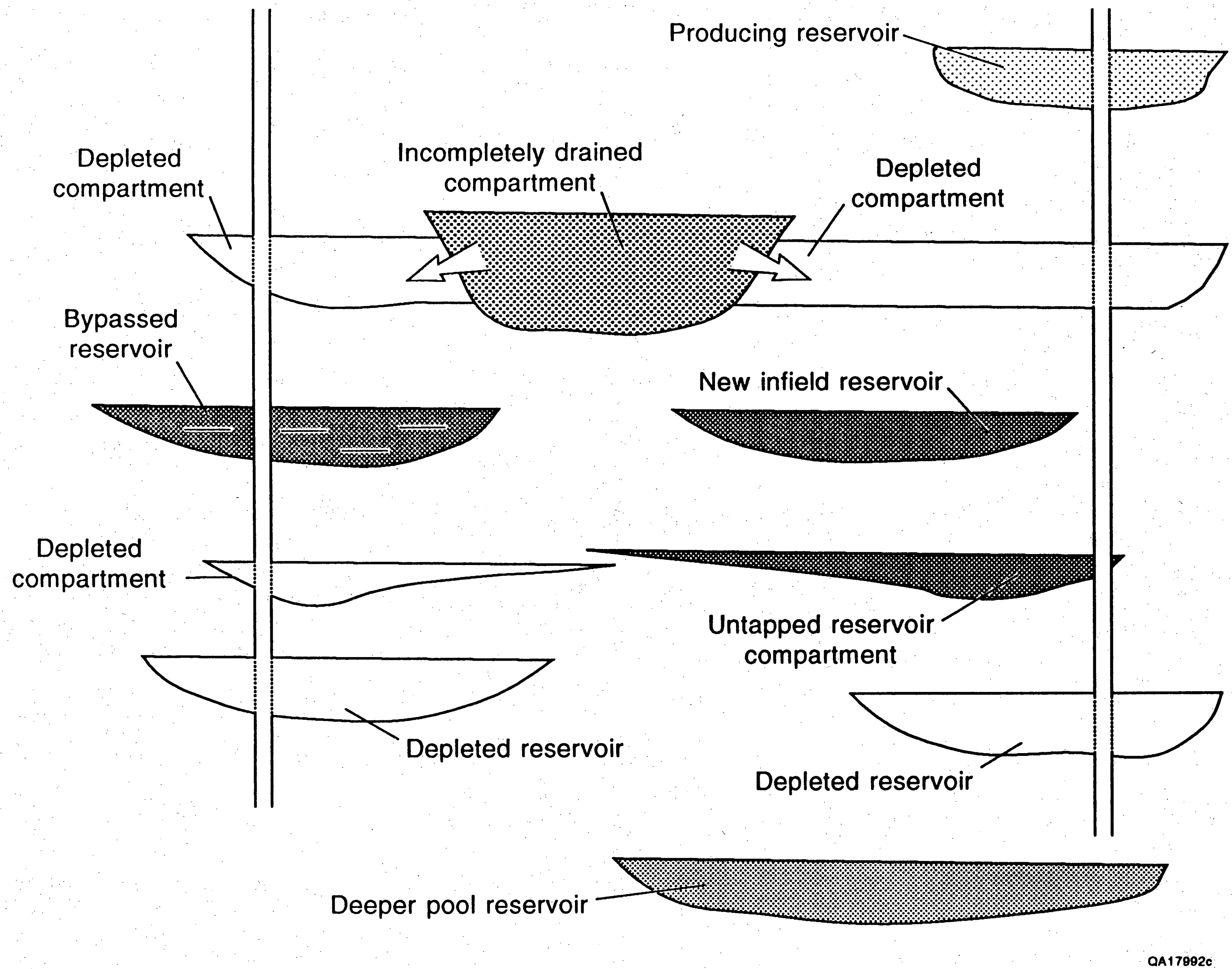


Figure 3. Diagram of reservoir-compartment terminology.

reservoirs are reservoirs not contacted during the original development of the field and are separated vertically and laterally from adjacent reservoirs. (2) *Untapped reservoir compartments* are produced by completions within a reservoir that are not easily identified as being separated either vertically or laterally from the established production within the same reservoir. New completions within untapped reservoir compartments are usually at or close to original reservoir pressure of the prior productive completions. (3) *Incompletely drained reservoir compartments* are also not easily identified as being separated vertically or laterally from a reservoir that is productive. The term "incompletely drained" refers to the ineffective drainage of the previous completions in the reservoir. Incompletely drained reservoir compartments reach an economic limit, and the recoverable resource without additional operational efforts such as stimulation or perforation in a laterally adjacent well bore will not be effectively drained. (4) *Bypassed reservoirs* are reservoirs contacted by existing well bores that have not been produced during the course of field development. Reservoirs may be bypassed because they were evaluated as nonproductive or uneconomic. These are typically shallower reservoirs that can now be reevaluated by reprocessing of the original logs, acquiring cased-hole logs in existing well bores, or using new open-hole higher resolution logging tools. (5) *Deeper pool reservoirs* are categorized as those reservoirs penetrated by drilling deeper either in existing well bores or in new infield wells adjacent to shallower wells, and below the previously established productive pools.

SYNOPSIS OF PROJECT RESEARCH RESULTS

Sandstone gas reservoirs account for approximately 90 of the 182 Tcf of recorded cumulative gas production from major Texas gas reservoirs defined as those reservoirs that have more than 10 Bcf of cumulative production. Total recorded Texas production is estimated to be 300 Tcf when all reservoirs are included. Reservoirs investigated by this research project lie within the Oligocene-age Frio and Vicksburg Formations and the Eocene-age Wilcox Group. These three major stratigraphic units form multiple gas plays (Kosters and others, 1989) and are part of eight major offlapping depositional episodes of the Cenozoic (fig. 4). Plays included in this research project include the Frio Fluvial/Deltaic Sandstone along the Vicksburg Fault Zone, Vicksburg Deltaic Sandstones in the Rio Grande Embayment, and Wilcox Deltaic Sandstones in the Houston Embayment. They incorporate major progradational, siliciclastic depositional episodes of the northwestern part of the Gulf Coast Basin depositional fill. The siliciclastic progradational wedges associated with the trends of the Frio, Vicksburg, and Wilcox have produced a cumulative gas volume of more than 55 Tcf through January 1, 1987, accounting for almost two-thirds (62 percent) of 90 Tcf of gas production from all Gulf Coast siliciclastic reservoirs (fig. 5). Cumulative production through 1986 from these three plays exceeds 18 Tcf of gas in reservoirs that are more than 10 Bcf. Fluvial and deltaic reservoirs in the Gulf Coast Basin are being targeted as a data-rich natural laboratory for evaluating infield development opportunities in fields that are 30 to more than 50 years old. Four gas fields in these three gas plays in the Gulf Coast Basin have been the sites of project research, data collection, analysis, and interpretation: Lake Creek (WX-1), McAllen Ranch (VK-1), Seeligson, and Stratton (FR-4) (fig. 2).

WILCOX GROUP

The four Wilcox gas plays in Texas account for more than 11 Tcf of natural gas production through 1986. Wilcox deltaic reservoirs were investigated in the Lake Creek field of Montgomery County, which was discovered in 1941 and produced more than 120 Bcf of gas through 1989 (Grigsby and others, 1992; Guevara and Grigsby, 1992). Close cooperation with Mobil Exploration and Production U.S., Inc., has resulted in data acquisition in three project cooperative wells between 1989 and 1991 (Mobil Lake Creek Unit Nos. 29, 47, and 48). Whole cores, incremental logs including wireline pressure tests, resistivity measurement while drilling, microresistivity borehole images, dipole sonic logs, and vertical seismic profiles (VSP's) were used to investigate reservoir heterogeneity in deltaic gas reservoirs of late Paleocene to early

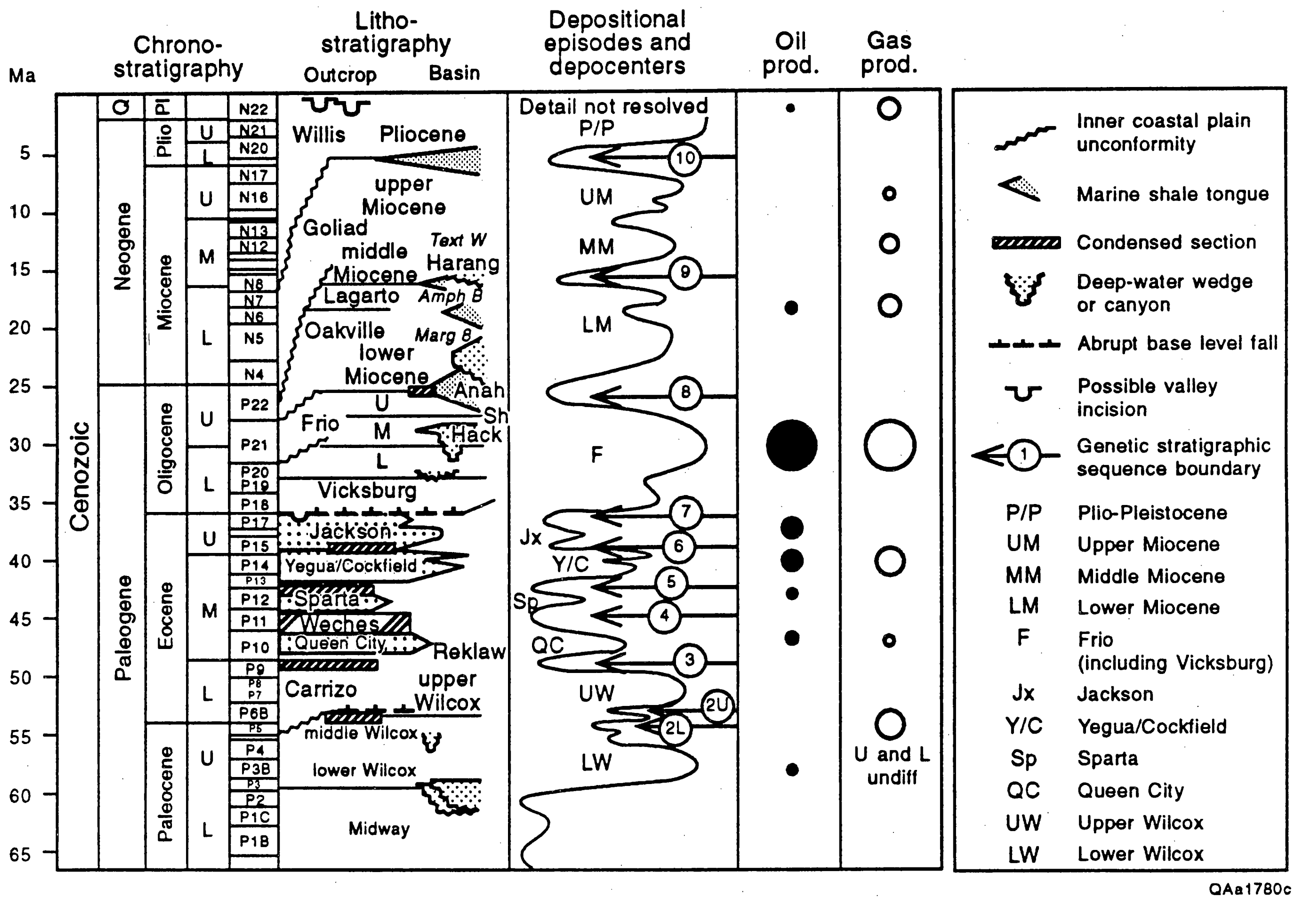


Figure 4. Relative ranking of the volume of gas produced from the eight major offlapping depositional episodes of the onshore Gulf Coast Basin.

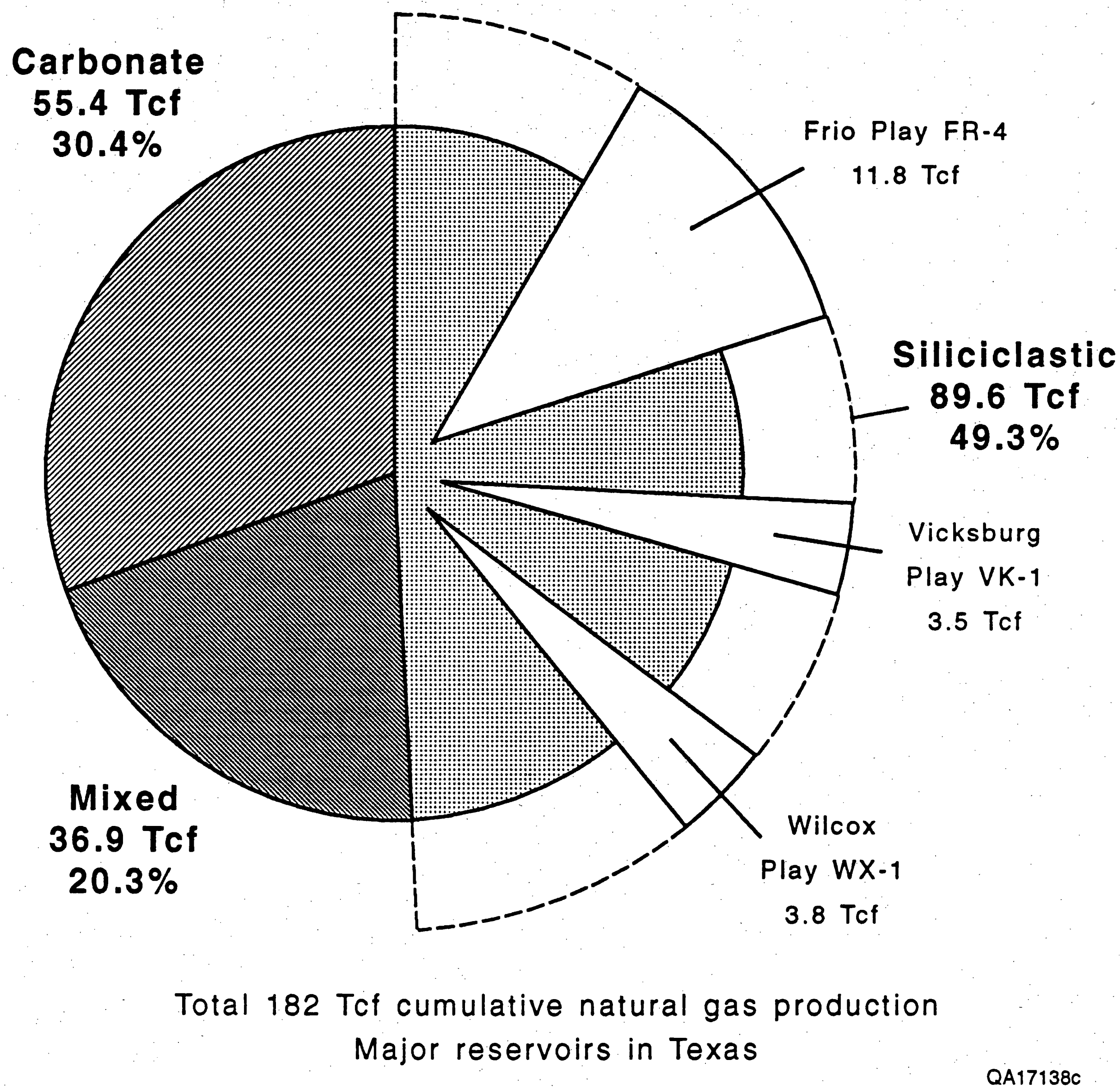


Figure 5. Lithologic distribution of gas production from major Texas gas reservoirs and contribution of the three major gas plays being investigated by the Secondary Natural Gas Recovery project.

Eocene age in the lower Wilcox Group at depths of greater than 9,000 ft (fig. 6). Gas-productive reservoir facies are primarily delta-front and distributary-channel-fill sandstones.

Hydrocarbons in Lake Creek field are trapped in rollover anticlines along the Wilcox growth fault zone (fig. 7). Interpretations of well logs and cores show that four operational reservoirs in the G-sandstone are related to at least four parasequences (fig. 8) of the lower Wilcox Rockdale delta system identified by Fisher and McGowen (1967). Individual lower Wilcox reservoirs are not seismically detectable on two-dimensional reflection seismic data.

Evaluation of heterogeneous deltaic gas reservoirs in Lake Creek field indicates that an SGR strategy of targeting distributary channels in the developed and downdip flank areas could access 8.7 Bcf of incremental gas resources in just 1 of the 18 gas condensate deltaic reservoir packages in the Wilcox Group. Original gas in place (OGIP) of 63 Bcf was assessed for two of the four deltaic parasequences in the lower Wilcox G reservoir in Lake Creek field. A conservative estimate of the corresponding recoverable gas in place (RGIP) is 23.1 Bcf, of which the current estimated ultimate recovery (EUR) is 14.4 Bcf. Thus, 38 percent of the RGIP, 8.7 Bcf, represents a secondary gas resource. Most of this secondary gas resource is located downdip from existing development. Reservoir facies consist of delta-front, channel-mouth-bar, and distributary-channel sandstones. Stratigraphic architecture of gas reservoir units shows that laterally extensive, sandstone-rich delta-front facies are capped by transgressive delta-destructional sandstones. Permeability analysis indicates that the channel-mouth bars are "sweet spots" that represent the best opportunity for incremental gas reserves in stratigraphically controlled parts of the delta complex (fig. 9). Engineering evaluations of recovery and production performance indicate that the most effective development strategy involves targeting completions in the distributary-channel facies. Analysis of gas productivity by facies shows that distributary-channel completions have 2.3 times the kh (14.1 versus 6.2 md-ft) and 3.9 times the EUR (2,265 versus 581 MMcf) of the nonchannel completions (table 1). The effective drainage areas for distributary-channel completions were found to be 200 acres (or greater), compared to 40 acres for nonchannel completions. This research shows that in the

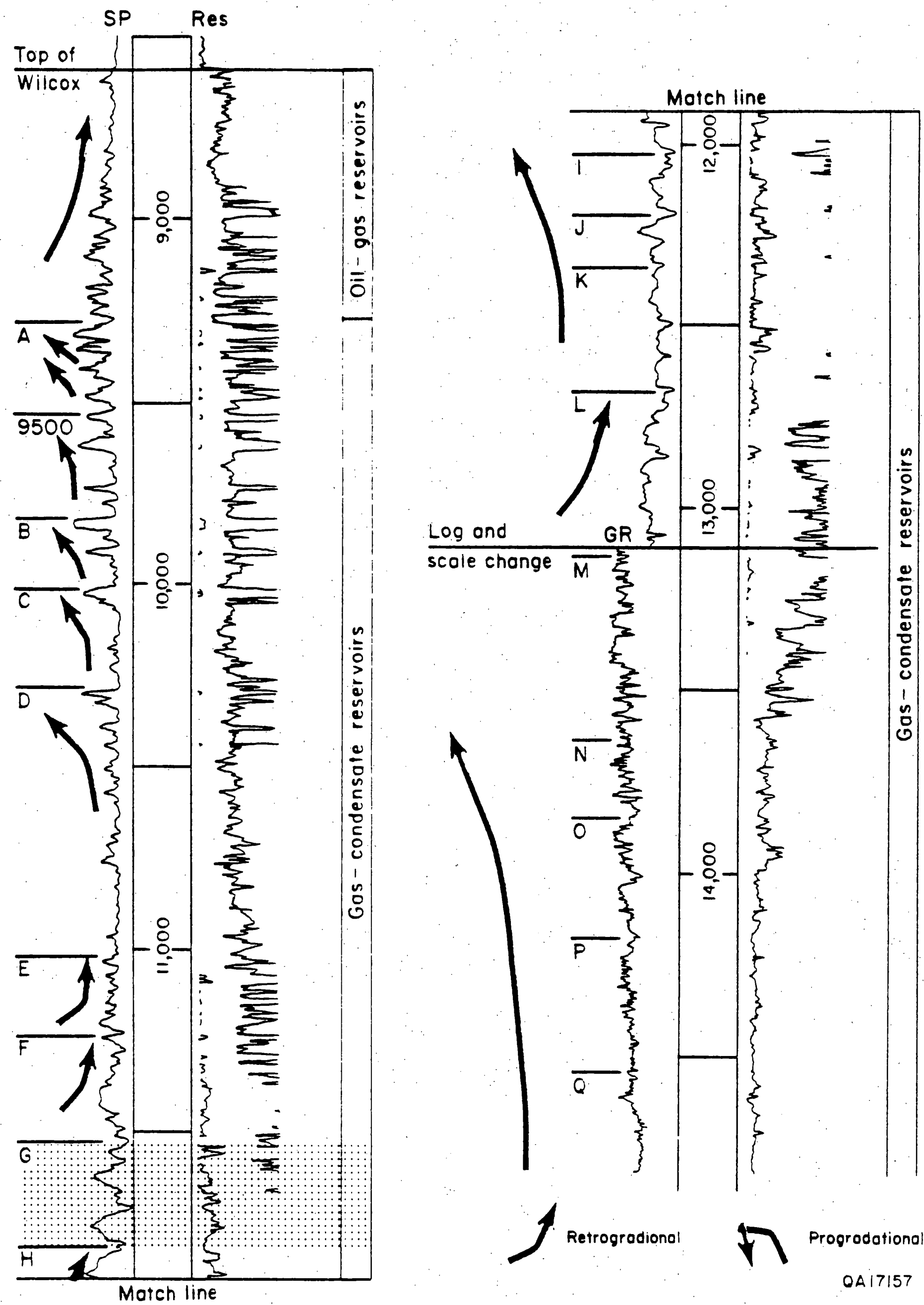


Figure 6. Type log (LCU No. 36) for Lake Creek field showing oil/gas reservoirs (La Gloria and G-1 through G-5 sandstones) and the underlying gas-condensate reservoirs (A to Q sandstones) of the Wilcox Group (after Guevara and Grigsby, 1992).

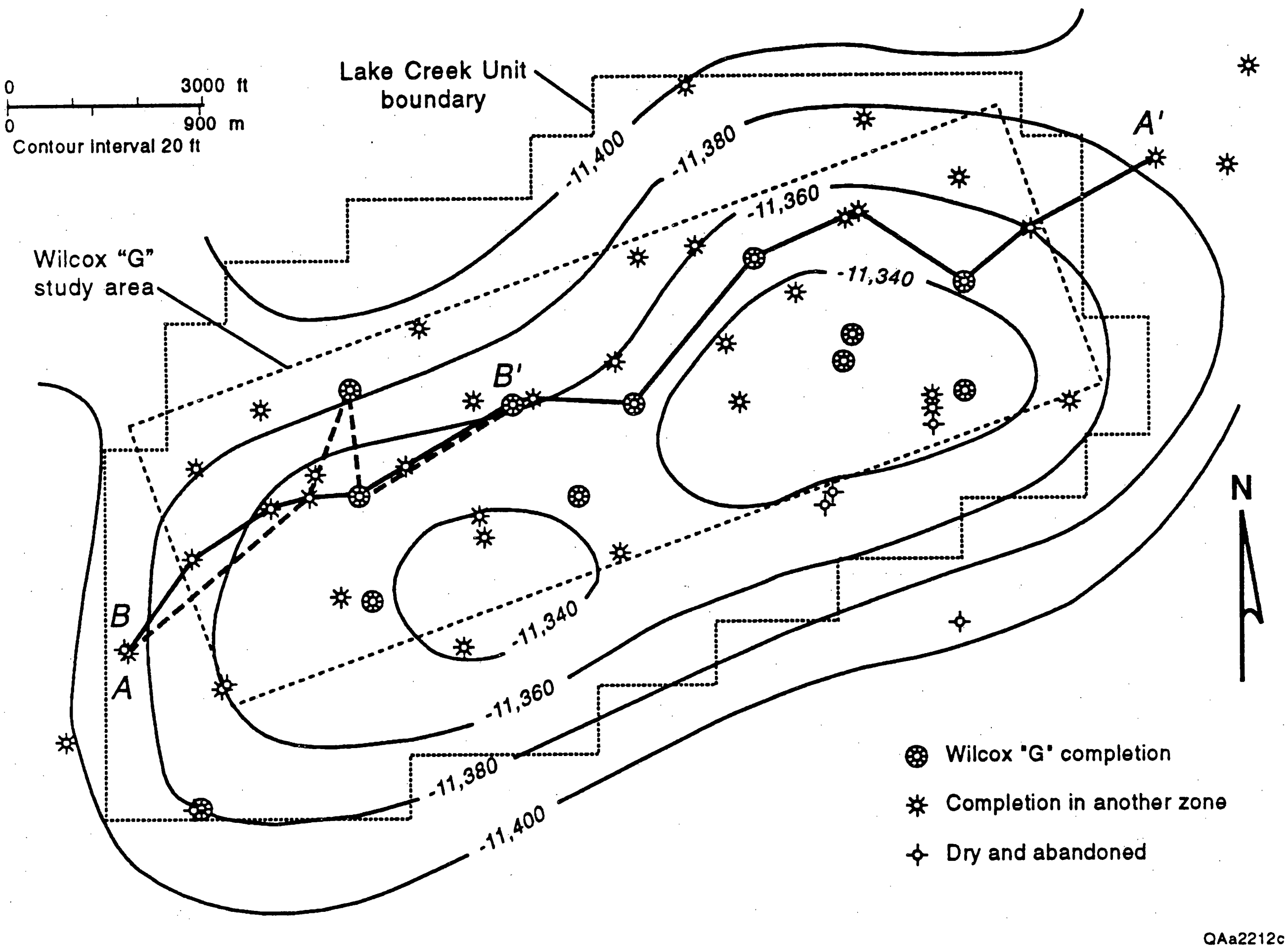


Figure 7. Map showing the structure of the Wilcox on the top of the G-2 sandstone. Structural closure is interpreted at –11,327 ft.

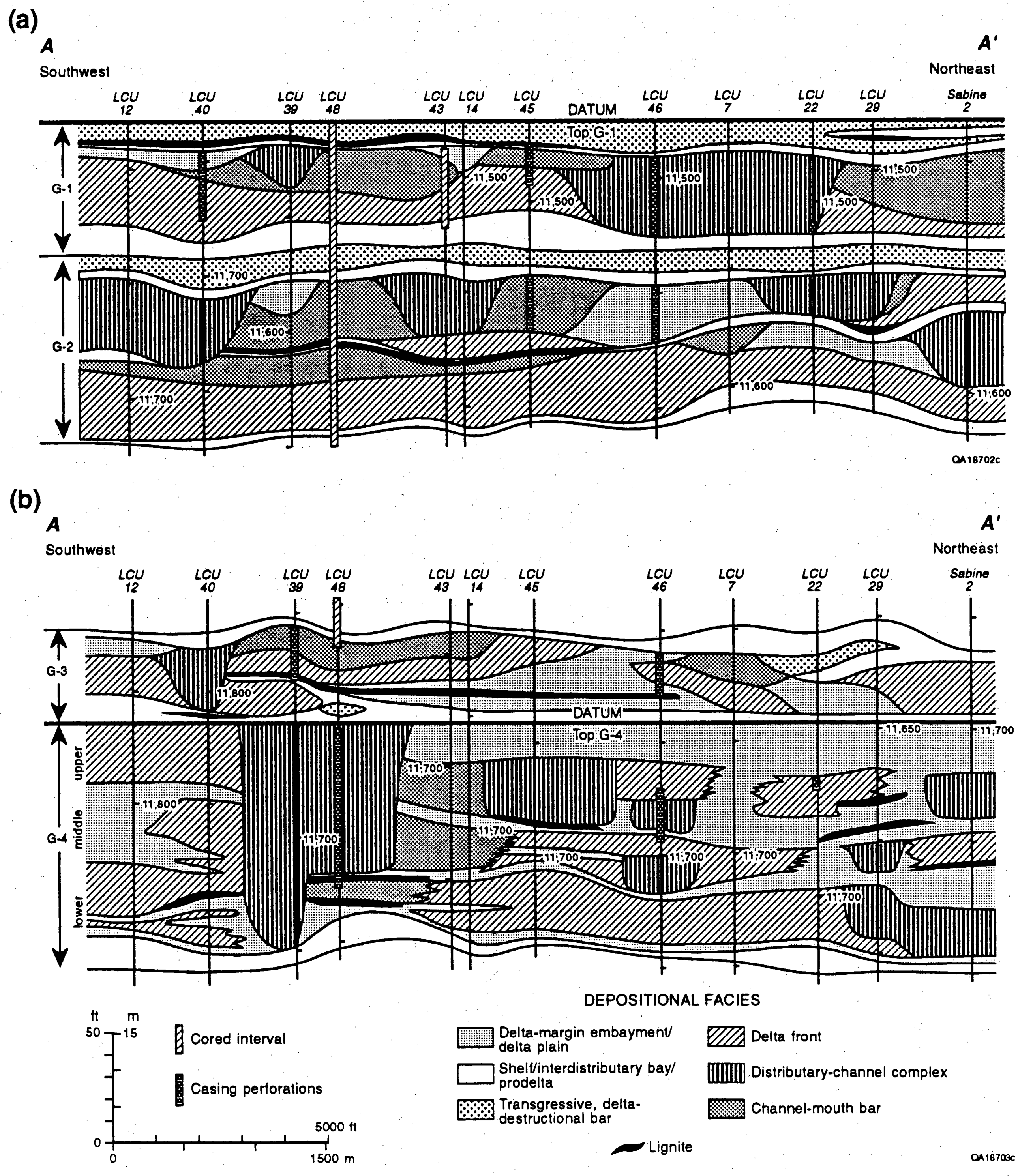


Figure 8. (a) Depositional strike-oriented cross sections showing (a) parasequences G-1 and G-2 and (b) G-3 and G-4 in the G sandstone interval across Lake Creek field.

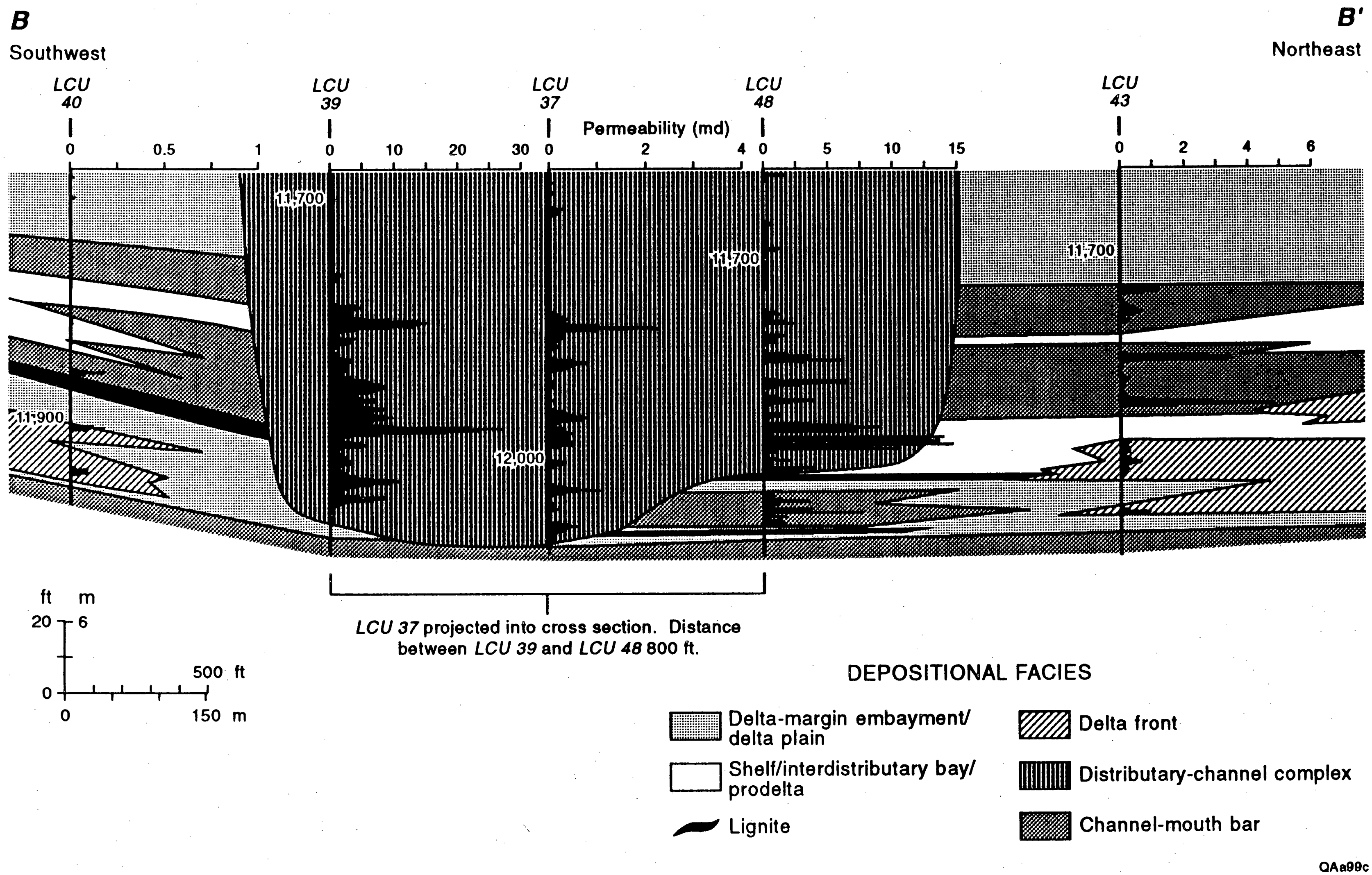


Figure 9. Permeability profiles of a channel of the G-4 reservoir, Lake Creek field.

Table 1. Engineering evaluation of recovery and production performance by depositional facies.

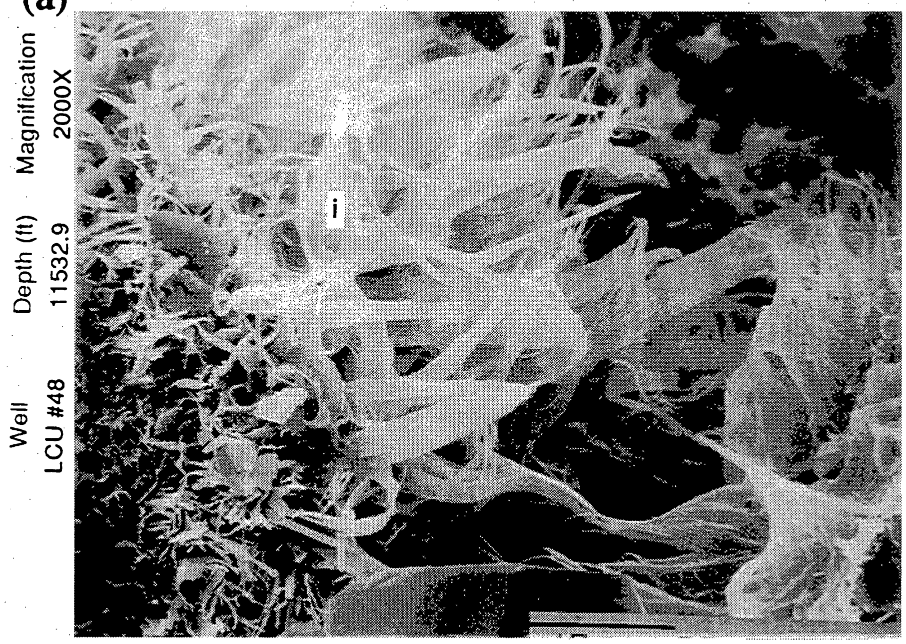
	Distributary-channel facies	**Nonchannel facies**
Mean effective kh (md-ft)	14.1 ± 4.1	6.2 ± 2.7
Mean estimated ultimate recovery per well (Bcf)	2.3 ± 0.9	0.6 ± 0.2

Wilcox deltaic reservoirs studied, well productivity is a strong function of depositional facies, diagenesis, and capillarity. Because the delta distributary-channel completions have more than twice the effective kh of nonchannel facies completions, delta distributary-channel completions offer twice the maximum opportunities for deliverability and reserves.

Mineralogic composition of the deltaic gas reservoir intervals in the Wilcox G sandstone is also important to gas producibility. The major authigenic minerals are quartz overgrowths and fibrous illite. Although quartz overgrowths have resulted in a permanent reduction in intergranular porosity in G sandstone reservoirs, this research found that fibrous illite, extending into and bridging pore throats, plays a major role in reducing permeability. Fibrous illite is rare in upper Wilcox gas and oil sandstones in South Texas (May and Stonecipher, 1990), but its presence in lower Wilcox gas sandstones and its possible effects on reservoir quality and production have been suggested in a previous work (Guven and others, 1980). The acquisition of preserved core from the LCU No. 48 well in Lake Creek field has provided the opportunity to determine the effects of drying on fibrous illite morphology and on permeability measurements. Fibrous illite ranges from 3 to 8 percent of the whole rock volume and reduces the permeability in the lower Wilcox G sandstones. Because the illite collapses upon extraction and drying during conventional core analysis, the dry (core) permeabilities are 2 to 7 times greater (false highs) than in situ permeabilities. More representative values for permeability have been obtained by correcting the dry core measurements for the effects of fibrous illite in the G sandstone (fig. 10).

A new advanced capillary pressure model (ADCAP) (Hawkins and others, 1993) was employed to predict the downdip limits of gas production in the three reservoir facies. This technique, referred to as the ADCAP method, combines the equations by Thomeer (1960), Swanson (1981), and Pittman (1992). This ADCAP model relates the four important reservoir properties of porosity, water saturation, permeability, and capillary pressure to a single equation. Excellent matches were obtained between core and log-derived porosity, permeability, lithology, and water saturations. Permeability-thickness values derived from the

(a)



(b)

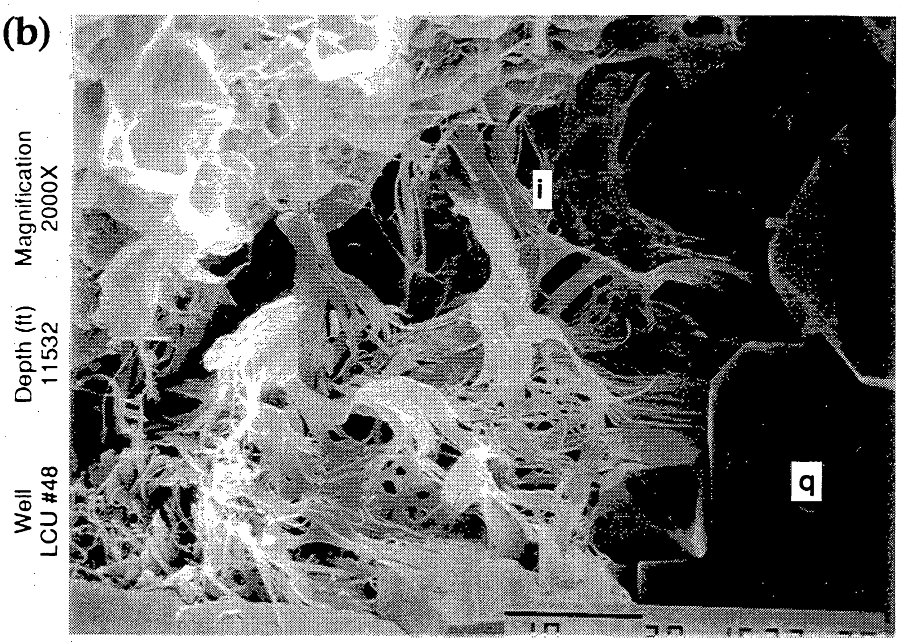


Figure 10. SEM photomicrographs of lower Wilcox G sandstones showing the effects of air drying on illite morphology. (a) Sample air dried at 60°F. Note the coalescence and partial collapse of illite fibers (i). (b) Sample that has undergone Dean-Stark extraction, methanol leaching, and air drying at 240°F. Note the total collapse of illite (i) against the pore walls (q = quartz overgrowths). Magnification is 2,000 ×. Bar scales equal 10 μm.

log model are in good agreement with those values from production tests and well tests. The effective gas permeability was corrected for overburden, Klinkenberg, fibrous illite, and relative permeability effects. The gas reservoirs in the lower Wilcox carry greater than 55 percent water saturation but produce water free. The minimum production limit is defined as 100 Mcf/d with 10 bbl of water.

The method for reserve estimation followed a five-step process. First, a map of facies distribution based on well logs calibrated to core data was used to compute the depositional facies volume. Second was the calculation of the water saturation, porosity, effective gas permeability, free water level, and transition zone thickness by facies using the ADCAP model. Third was the determination of the recovery factor evaluated by depth and facies. Fourth was to determine the RGIP by facies. Fifth was to compare the RGIP with current EUR from existing completions. The potential area containing the SGR resource is based on effective permeability to gas calculated from the mean value of air permeability for each reservoir facies and water saturation resulting from height above the free water level. A reservoir model of the capillary control of incremental gas resources is shown in figure 11.

Secondary gas recovery strategies to maximize natural gas recoveries in Wilcox Group or similar reservoirs include strategic placement of wells or targeted recompletions into distributary-channel reservoir facies with higher permeability where effective drainage areas are up to five times greater than nonchannel reservoir facies. The integrated SGR methods and concepts of capillarity used in analysis of these deltaic reservoirs in Lake Creek field are transportable and should help identify additional incremental gas resources in other heterogeneous gas fields with low- to conventional-permeability reservoirs.

VICKSBURG FORMATION

The three Vicksburg gas plays in Texas accounted for 3.7 Tcf of the natural gas production through 1986. SGR research focused on identification and prediction of compartmentalization of natural gas reservoirs in deltaic sandstones in the Rio Grande Embayment (VK-1 gas play)

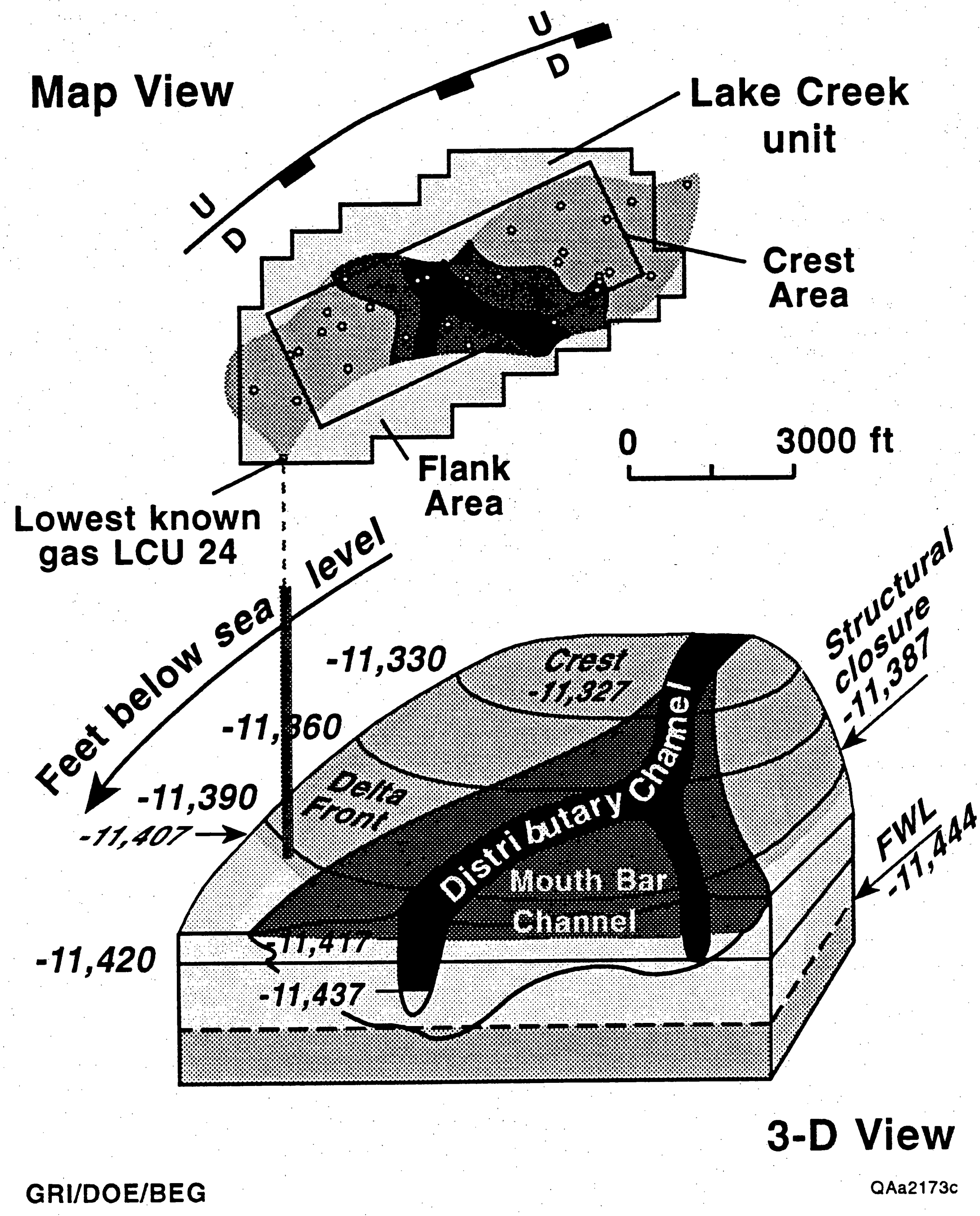


Figure 11. Reservoir model showing capillary control of incremental gas resources by facies.

(fig. 2). McAllen Ranch field in Hidalgo County has produced almost 700 Bcf of gas since its discovery in 1960. In 1989 and 1990 the SGR research project, in close cooperation with the operator of McAllen Ranch field (Shell Western Exploration & Production Inc.), led to an improved understanding of the depositional environment and diagenetic effects on both the geometry and the internal reservoir heterogeneities that affect gas recovery in deltaic gas reservoirs of the Oligocene Vicksburg Formation at depths below 11,000 ft (fig. 12) (Langford and others, 1992a). The concept of a uniform low-permeability reservoir alone cannot account for the observed pressure variability in the field. Results of the SGR research showed that heterogeneity in Vicksburg deltaic reservoirs includes facies and diagenetic variability. Facies heterogeneity is most prevalent in the proximal portions of the delta lobes.

Stratigraphic analysis indicates that the lower Vicksburg sandstones are part of a landward-stepping package deposited during an overall transgression of the South Texas coast. McAllen Ranch gas field is on the downthrown block of a major growth fault that was active during the early and middle Vicksburg deposition. Subregional two-dimensional seismic reflection data indicates that the growth fault is listric along a detachment surface in the Jackson shale (fig. 13). SGR research focused on the S reservoir package in the Vicksburg in the northern part of McAllen Ranch field, the B area, where SWEPI conducted a three-dimensional seismic reflection survey, and was actively drilling and completing infield wells that presented the opportunity for cooperative data gathering (fig. 14). The S reservoir sandstones form tapering wedges that pinch out and become shaly to the north and northeast (fig. 15). A structure-contour map of the S reservoir indicates that the B area is much less faulted than the other productive parts of the S reservoir (fig. 16).

SGR project participation with the operator included two cooperative wells (SWEPI A. A. McAllen Ranch Nos. B-17 and B-18) involving extensive coring of the reservoir facies, incremental high-resolution open-hole logging, and both zero and far-offset VSP's. Six major parasequences within the highly productive S reservoir interval were identified from detailed well log correlations (fig. 17). Gas-productive reservoir facies are primarily delta-front and

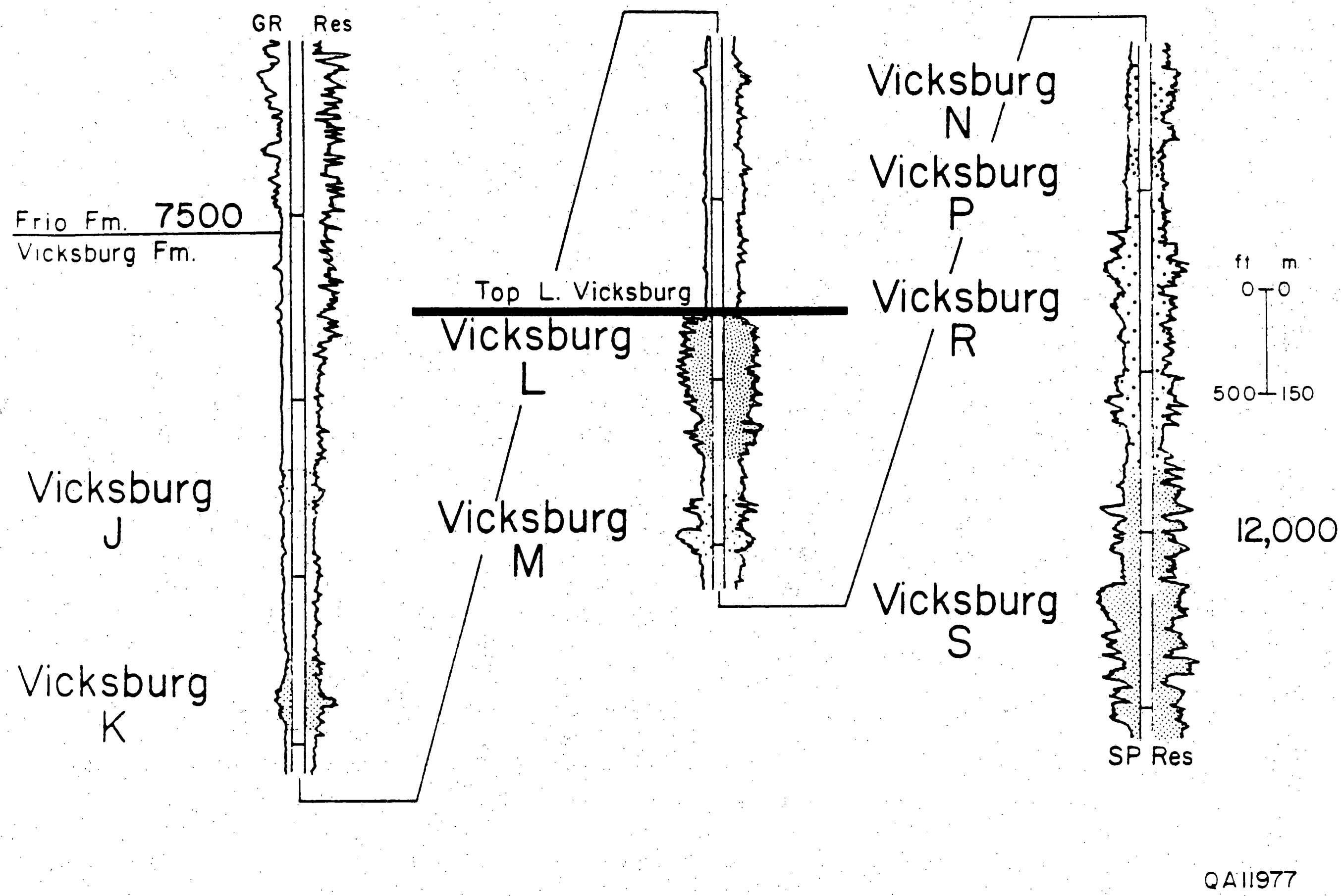


Figure 12. Type log (A. A. McAllen No. 14) illustrating stratigraphy of the reservoir sandstones in the Vicksburg section at McAllen Ranch field.

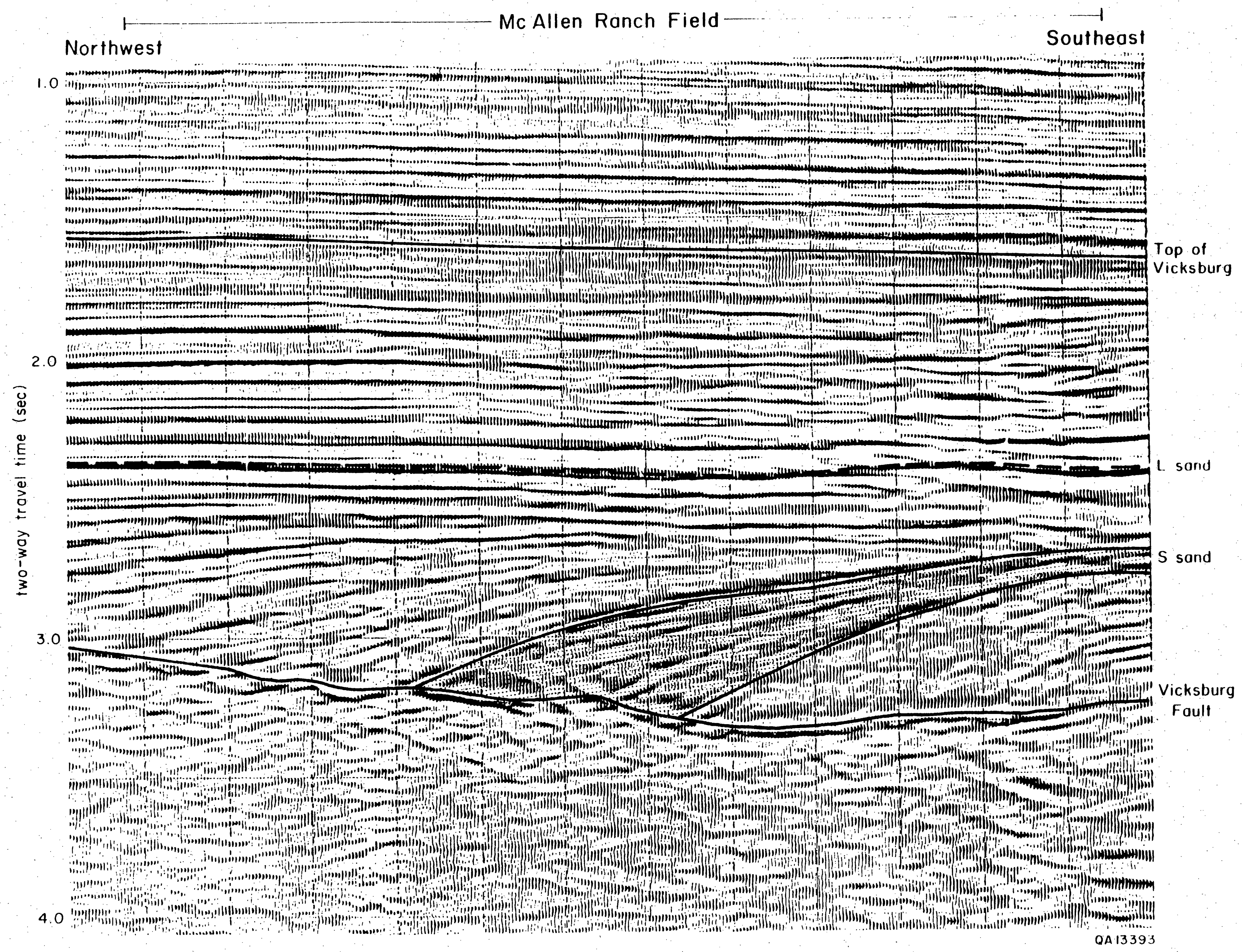


Figure 13. Dip-oriented seismic line showing selected gas reservoirs in McAllen Ranch field and the underlying fault contact with the Eocene Jackson Group.

Figure 14. Index map of McAllen Ranch field showing the distribution of wells and cores available for this study. Inset map shows location of field. Lines are traces of cross sections. Cross section B–B′ shown in figure 18. Cross section C–C′ shown in figure 19.

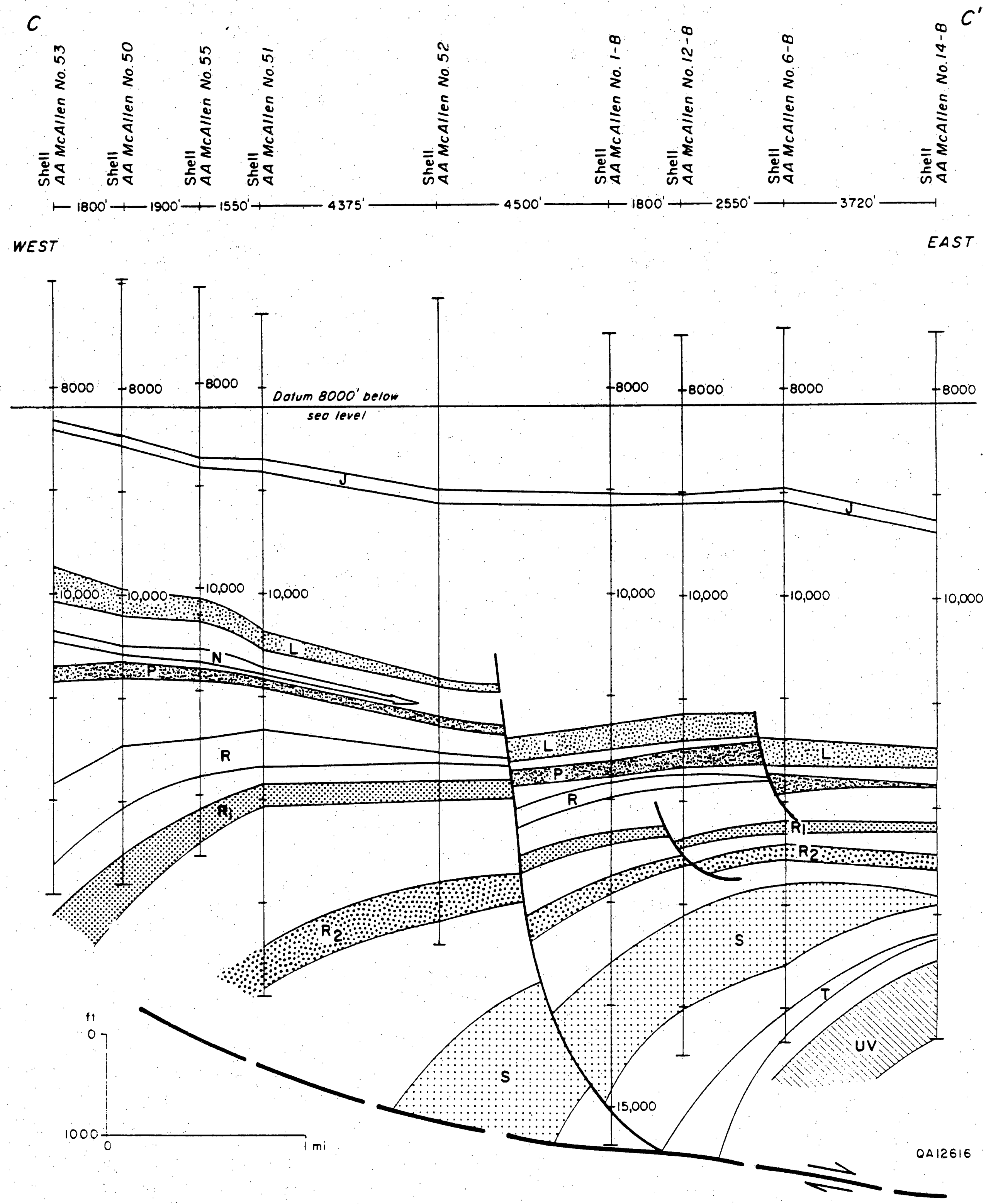


Figure 15. West-to-east cross section C–C′ through the northern part of McAllen Ranch field showing rollover into the growth fault shown in figure 13. Location shown in figure 14.

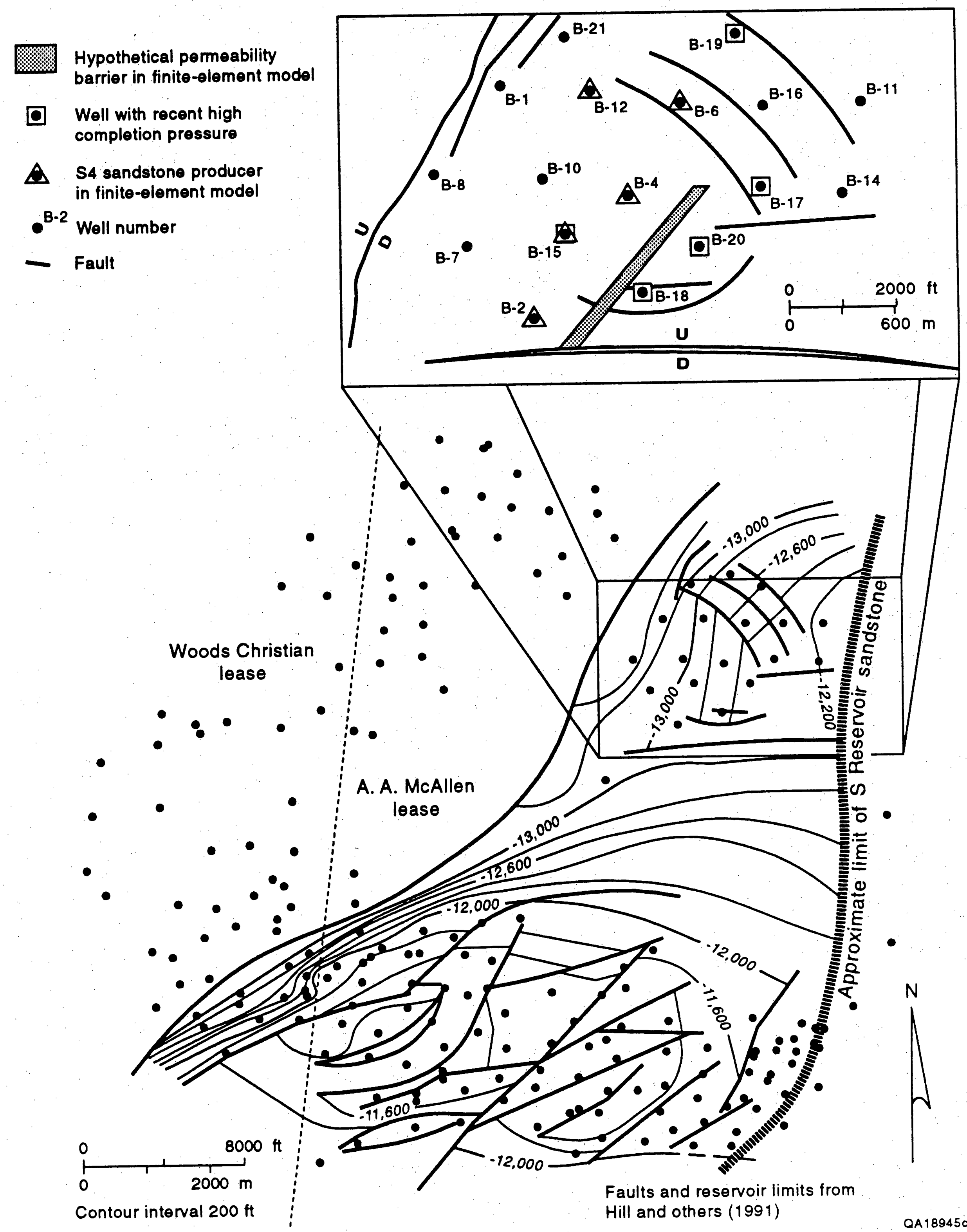


Figure 16. Structure map contoured on top of the S reservoir. Although the B area is much less faulted than the rest of the S reservoir producing area, there is a greater density of mapped faults owing to the high-quality, 3-D seismic data that allow delineation of faults having small throws.

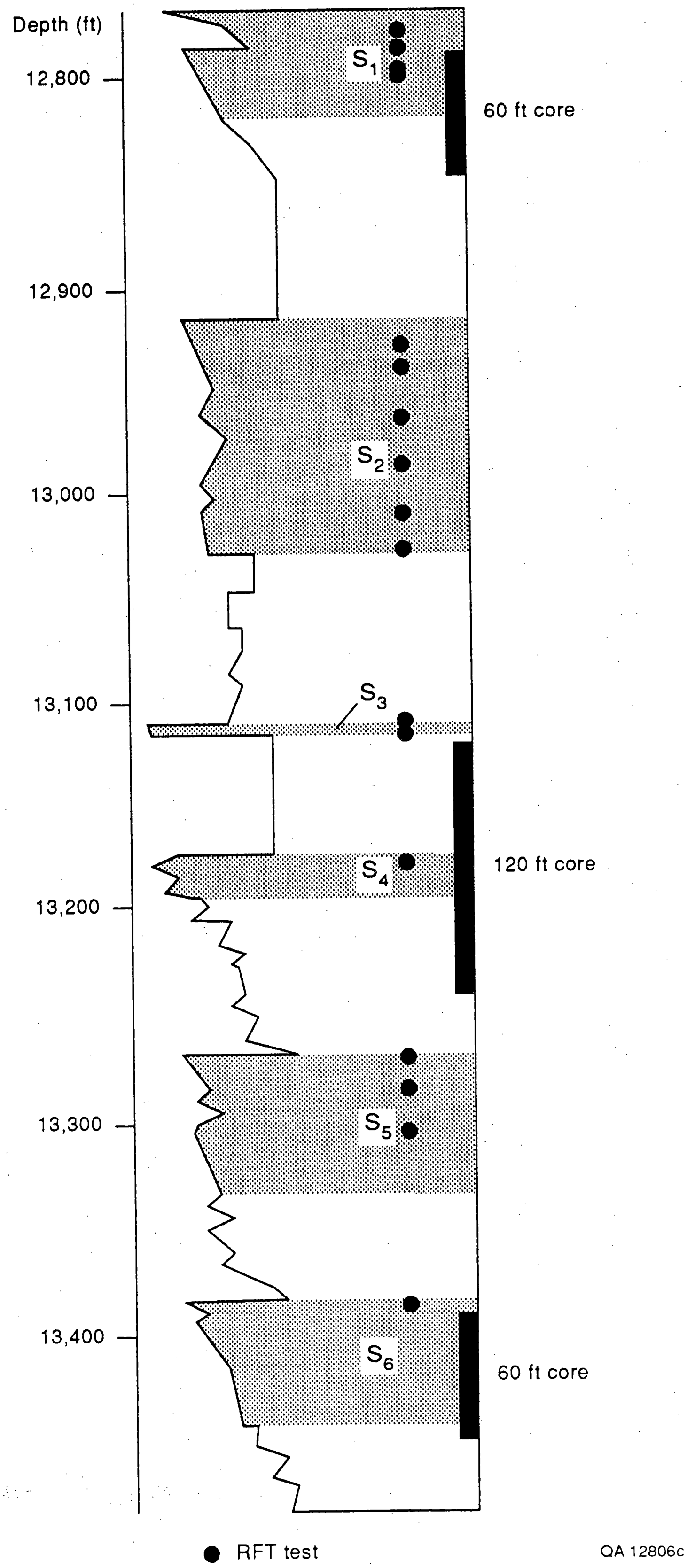


Figure 17. S reservoir stratigraphy in the Shell A. A. McAllen No. B-18 well showing S_1 through S_6 sandstone intervals and location of cores and wireline pressure measurements taken for this project.

distributary-channel-fill sandstones. The most common facies are the delta-front sandstones, which are thicker and more laterally continuous than the other facies. Stratigraphic cross sections of the S sandstone across the entire field show that distributary-channel facies occur only in the western part of the S reservoir, which is interpreted to represent the proximal part of the delta (fig. 18). The massive upper delta-mouth-bar and shoreface facies are widely distributed across the field but most abundant and thickest in the B area to the northeast. Reevaluation of two-dimensional seismic profiles and analysis of a three-dimensional seismic survey by the operator were critical in substantiating new drilling opportunities by indicating the actual extent of the reservoir interval beyond the mapped limits of previous production (fig. 19). Concurrent analysis by the SGR project research team and the operator resulted in the identification of significant secondary gas resources. Additional infield drilling of new wells to the S reservoir has added more than 100 Bcf of booked reserves to this 30-year-old field since 1987 (Hill and others, 1991).

Close correlation of petrographic analysis from project cores and interpretation of open-hole logs enabled mapping of chlorite and calcite diagenetic cements in the reservoir intervals, which reduce the effective drainage radius of producing zones. Diagenesis creates significant permeability barriers in lower Vicksburg reservoirs. Microresistivity logs acquired during the high-resolution dipmeter logging reveal differences in cementation and specific depositional facies of the reservoir (fig. 20) (Langford and others, 1992b). Because many Vicksburg reservoirs have reduced permeability, pressure-interference testing between wells was not feasible. An alternative approach by the SGR project was to implement a two-dimensional finite-element simulation of the S reservoir (fig. 21), which integrated geologic, petrographic, formation-evaluation, and engineering data. The reservoir simulation modeling supported the lack of communication between reservoirs penetrated by cooperative wells with the adjacent long-term production (more than 20 yr) from reservoirs comprising laterally continuous nearshore delta-front sandstones (fig. 22). Accurate evaluation of shaly sandstone reservoirs is also a significant problem in lower Vicksburg reservoirs. Gas reserve volumes will be underestimated if

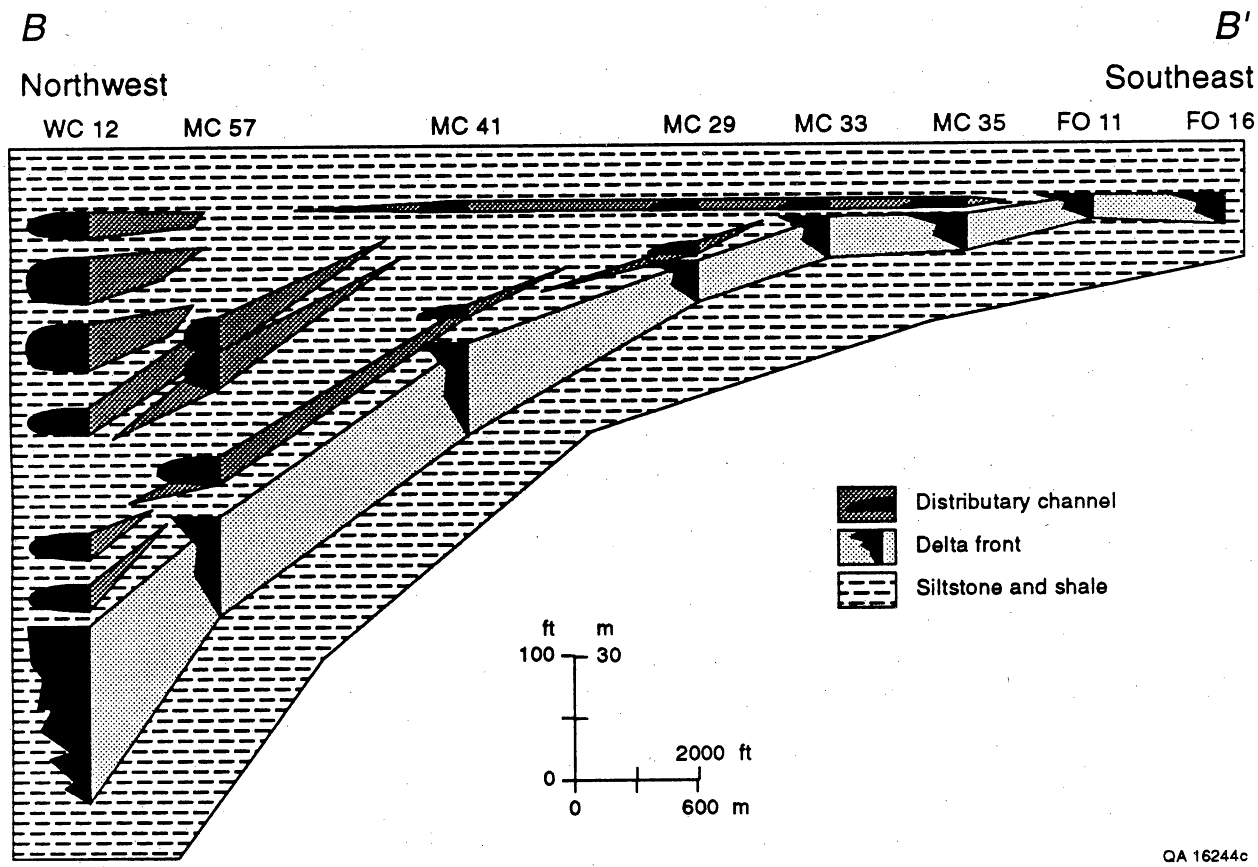


Figure 18. Northwest-to-southeast cross section B–B′ through the S_1 deltaic interval illustrating the south-to-north transition from distributary channels to shoreface sandstones at the top of the interval. Location shown in figure 14. Datum is the top of the S_1.

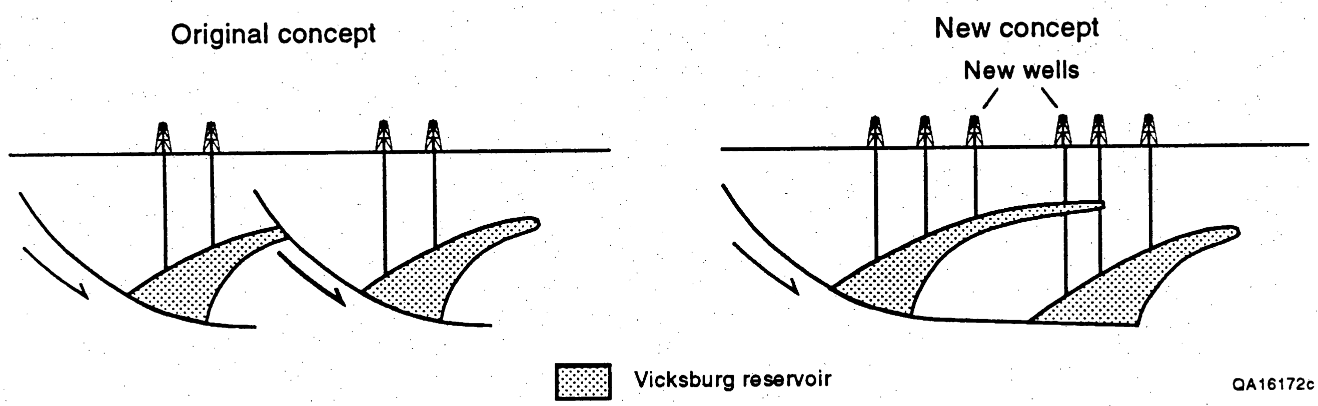


Figure 19. Schematic cross section showing the change in geologic concept that spurred Shell's 1989–1990 drilling campaign in the B area.

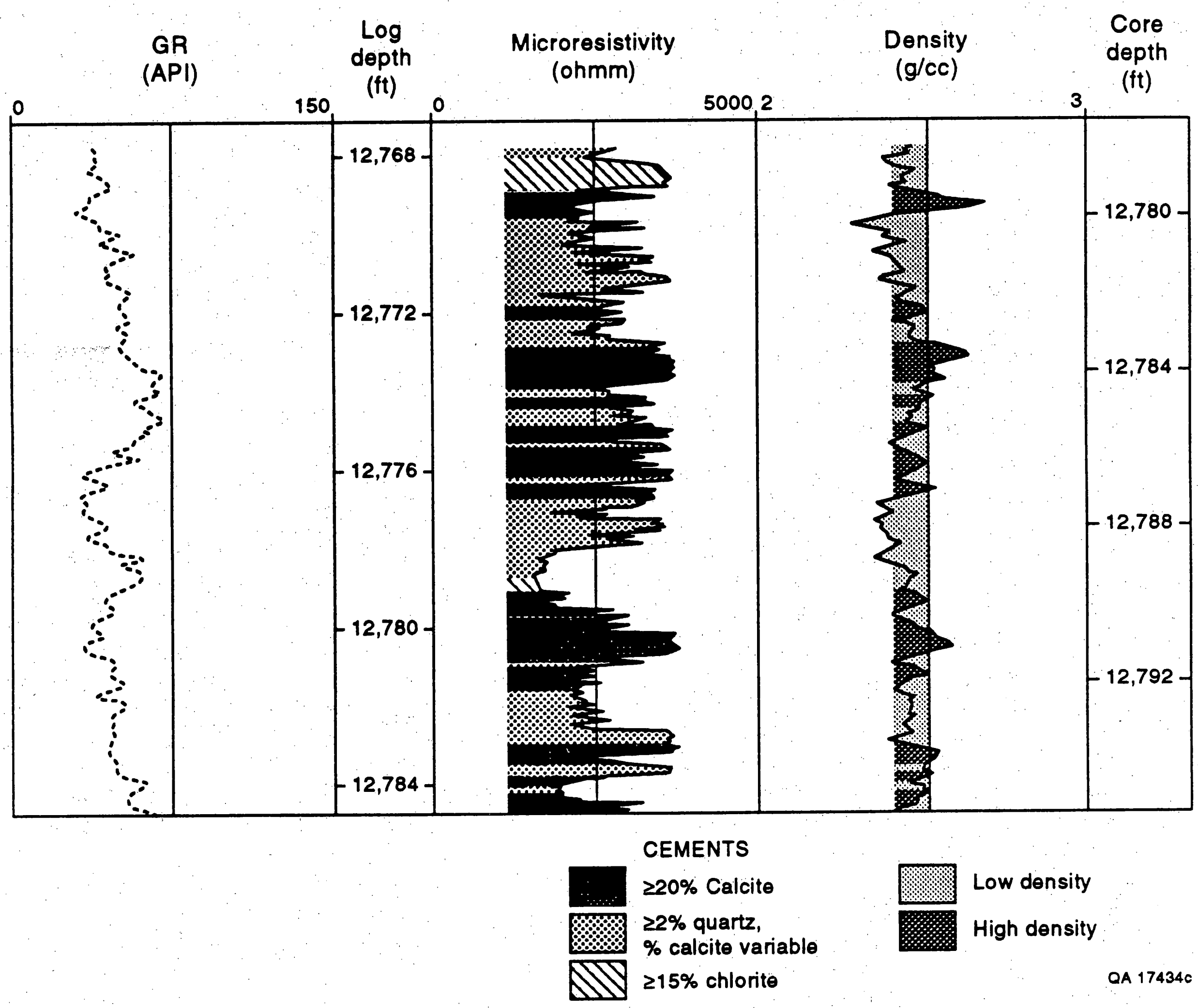


Figure 20. Section of the gamma-ray, microresistivity, and density logs from the Shell A. A. McAllen B-18 well illustrating the use of logs in interpreting diagenetic facies.

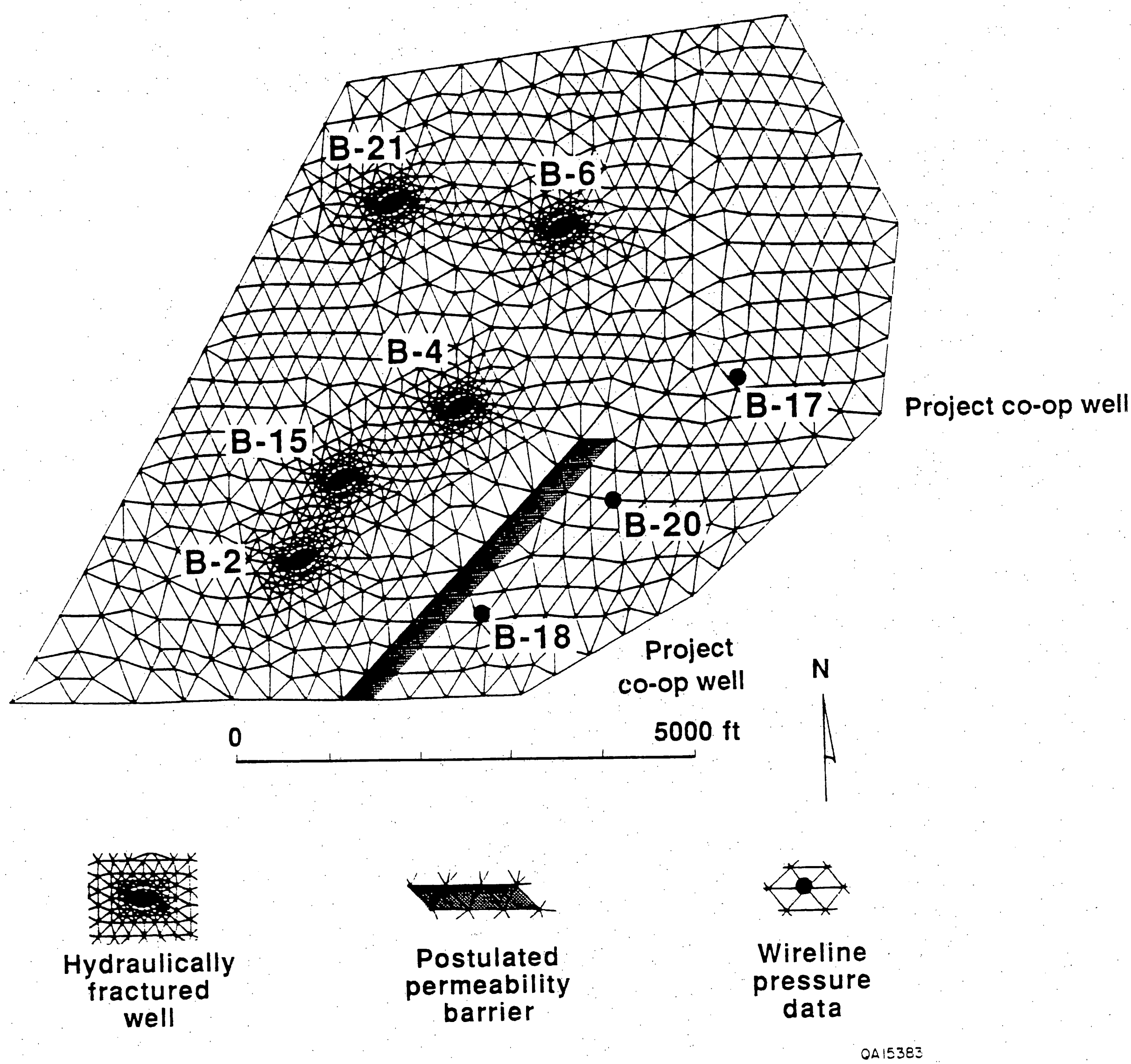


Figure 21. Finite-element grid for simulation study of the S_4 sandstone showing the location of one possible low-permeability barrier.

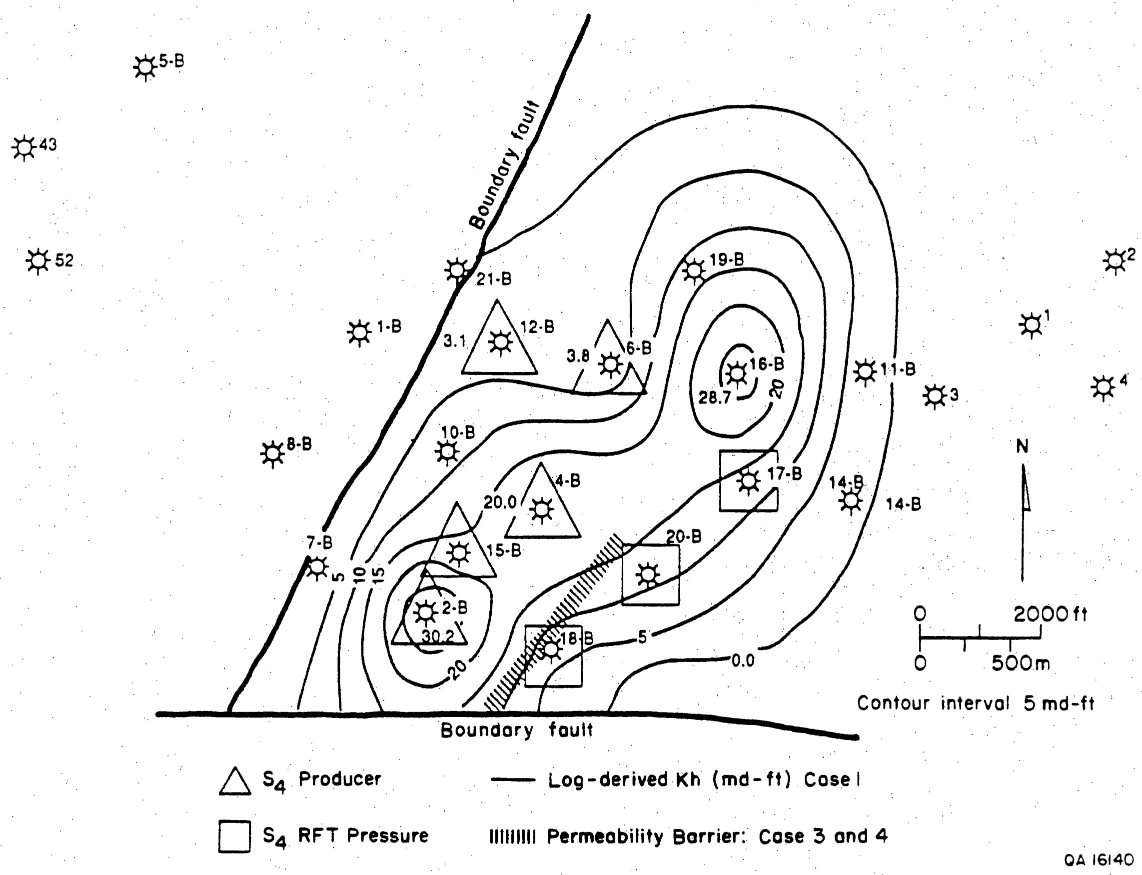


Figure 22. Permeability thickness map of the S_4 sandstone indicating the assigned position of the low-permeability flow barrier.

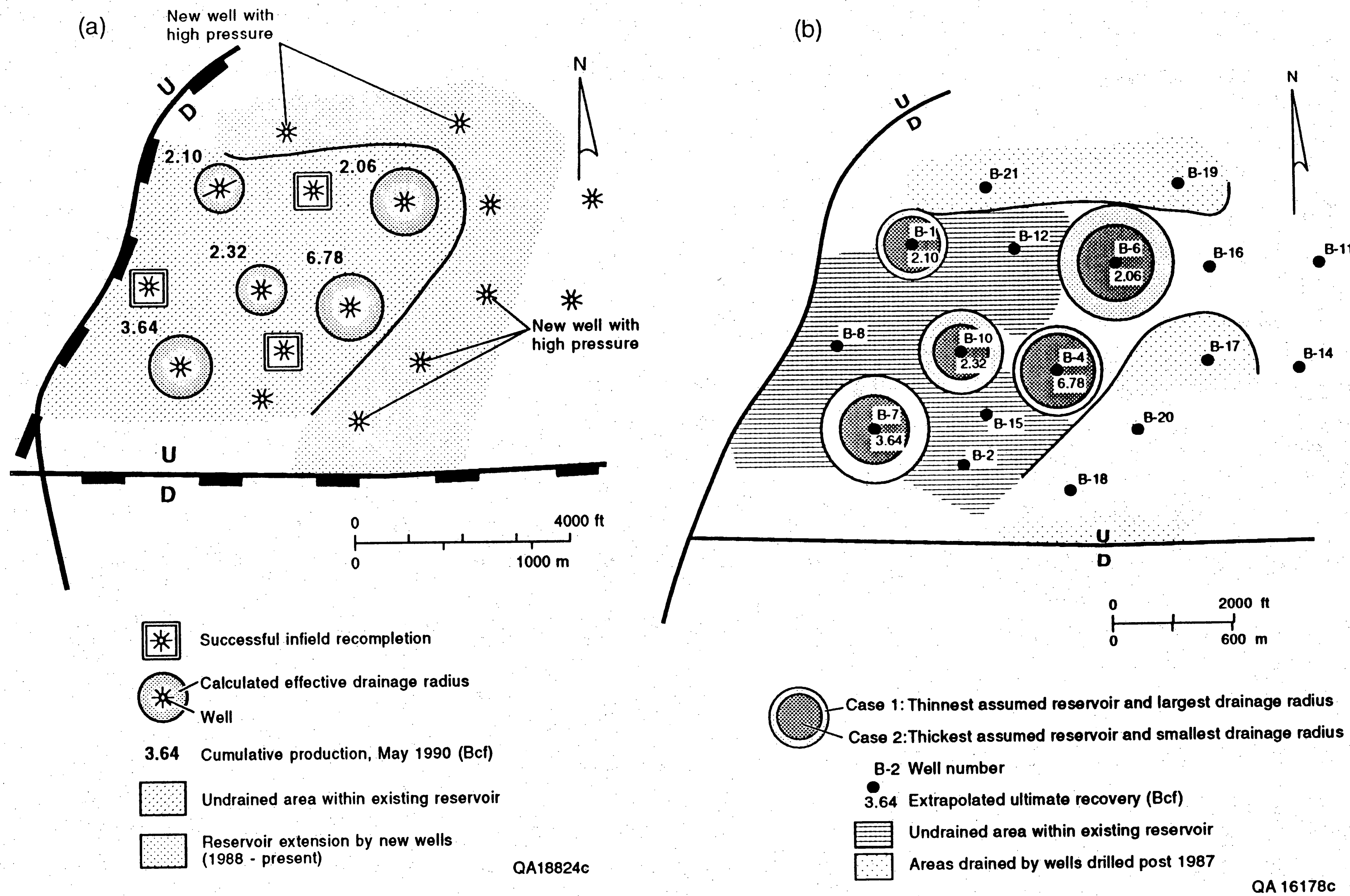


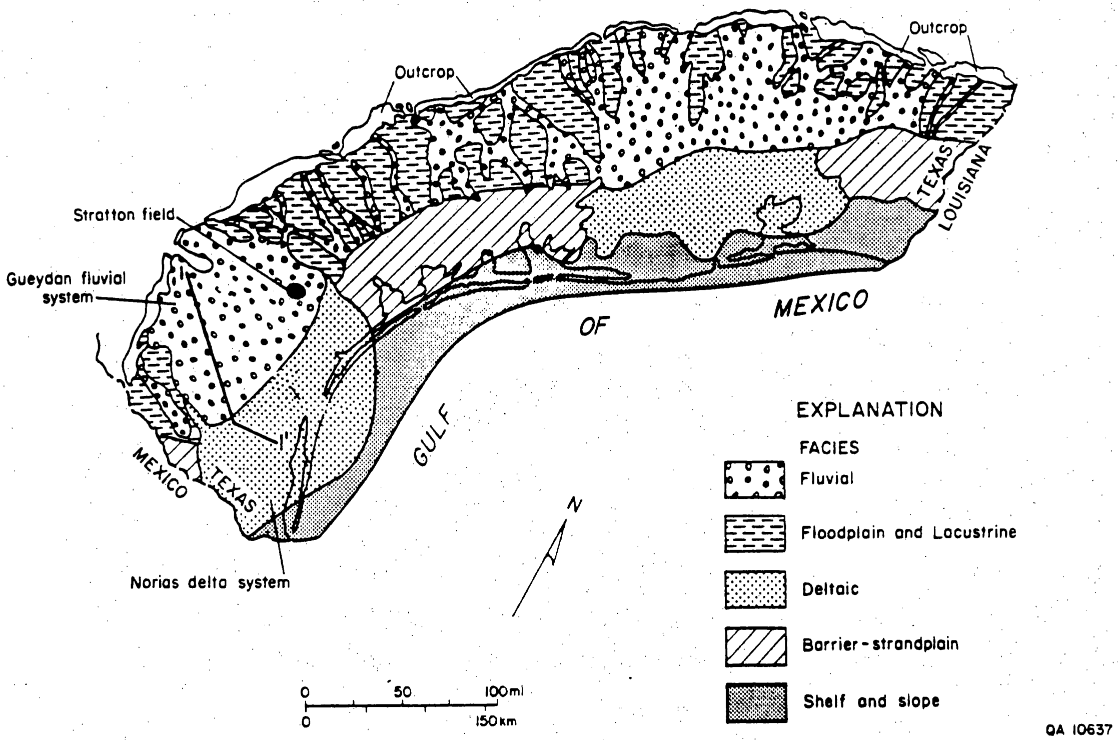
Figure 23. (a) Map showing estimated drainage areas for the S_2 completions in the B area with the calculated undrained volumes. (b) Map showing estimated drainage areas for the S_4 completions in the B area along with the calculated undrained volumes.

reservoir water saturations are not accurately defined. Improved log calibration of hydrocarbon saturation in the gas reservoir was achieved through specialized formation-evaluation analysis of project cores that included cation exchange capacity (CEC), X-ray analysis, and electrical properties of the reservoir. Identification of varying drainage areas on a sandstone-by-sandstone basis can lead to delineation of incremental gas resource potential. In the B area the effective drainage areas for wells in the S_2 and S_4 reservoirs are shown in figure 23. Three post-1990 infield recompletions by the operator within the S_2 reservoir have documented natural gas resources that were not effectively contacted by older wells (Langford and others, 1992a). Extrapolation of these results to Vicksburg and other natural gas reservoirs in similar structural and stratigraphic settings with restriction of gas flow caused by reservoir heterogeneity may provide opportunities for incremental gas reserves by infield drilling and recompletions.

FRIO FORMATION

The 10 Frio gas plays in Texas account for 41 Tcf of natural gas production through 1986. SGR research has focused on Stratton and Seeligson gas fields, which are located in parts of Jim Wells, Nueces, and Kleberg Counties in South Texas (Jirik, 1990; Kerr, 1990; Kerr and Jirik, 1990). Initial development of both of these fields started in 1937 and produced gas from Oligocene fluvial-dominated reservoirs in the middle Frio Formation at depths ranging from 4,500 to 7,000 ft. Reservoir facies are primarily channel-fill and splay sandstones associated with the Gueydan fluvial system (Galloway, 1977; Galloway and others, 1982) (fig. 24). Additional production from deeper Vicksburg reservoirs also occurs at both fields. Cumulative production from each field exceeds 1.5 Tcf of natural gas. Hydrocarbons are trapped in sandstone reservoirs in broad rollover anticlines (fig. 25).

Previous Bureau research programs at Seeligson field made this mature field a candidate for additional research (Jirik and others, 1989; Jirik, 1990). From 1988 through 1990, close cooperation with Oryx Energy Co., Mobil Exploration and Production U.S., Inc., and Mobil Research and Development Co. enabled open- and cased-hole data collection and VSP



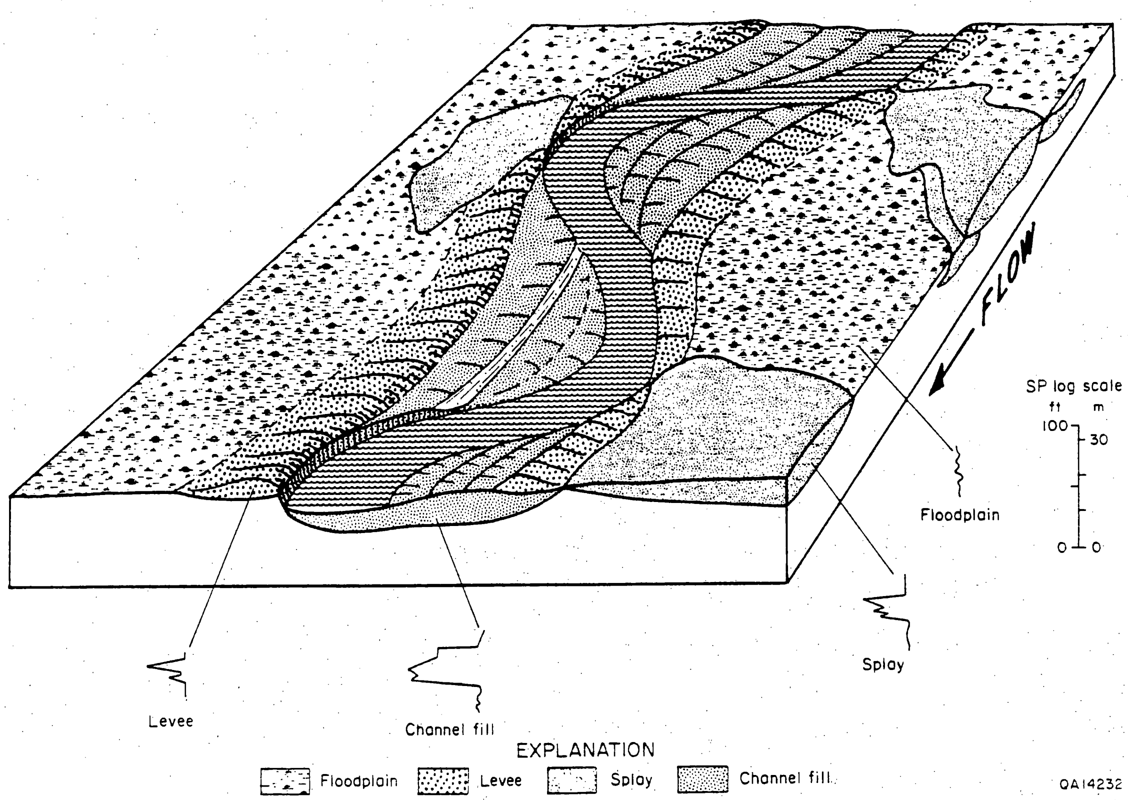


Figure 24. (a) Frio depositional systems in the Texas Gulf Coast. Middle and upper Frio sediments were deposited in the Gueydan fluvial system, in which low-sinuosity, bed-load stream deposits grade basinward into high-sinuosity, mixed-load stream deposits. Modified from Galloway and others (1982). (b) Three-dimensional facies relationships and characteristic SP log responses in middle and upper Frio fluvial reservoirs in Seeligson field (from Galloway, 1977).

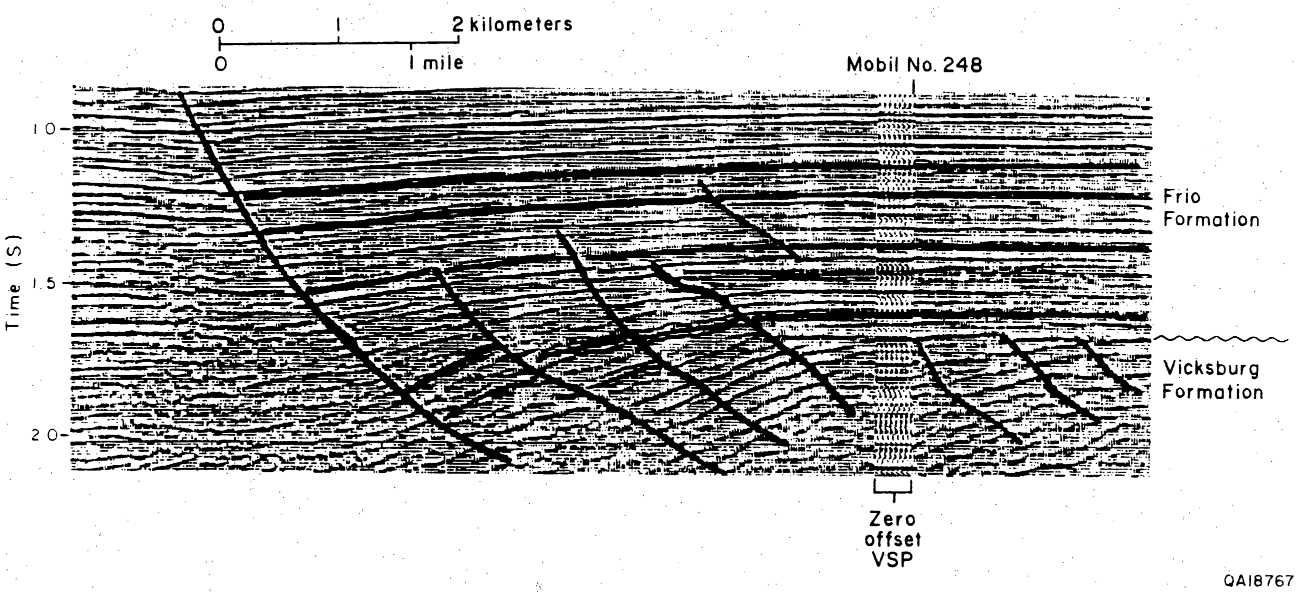


Figure 25. Structural seismic dip section E–E′ across Seeligson field with zero-offset VSP through the Mobil No. 248 Seeligson well. Line of section shown in figure 26.

acquisition in two cooperative wells (Mobil Seeligson Unit Well Nos. 47 and 48). Operations included wireline pressure testing, acquisition of open- and cased-hole logs, a borehole gravity survey, and both zero and far-offset VSP's. Further cooperation with Mobil and Oryx led to the development of a project experiment site that included access to five existing wellbores across a 1-mi^2 area of the field. A high-quality surface three-dimensional seismic survey and a unique three-dimensional reverse VSP survey using the Western Atlas downhole seismic source were conducted across the experiment site in 1990 (fig. 26). Both seismic-reflection amplitude and amplitude versus offset (AVO) images of parts of the middle Frio were compared with net-sandstone and log facies interpretations derived from log data. The strong correspondence of the three-dimensional image to the geologic interpretation indicates that detection of thin fluvial channel systems is possible and that seismic imaging is critical to defining reservoir compartment size and position (fig. 27). The reverse VSP data were analyzed by Mobil Research and Development Company. Plans for a series of pressure interference tests in wells within the three-dimensional seismic image volume were modified because of casing leaks that prevented accurate pressure measurements in key wells. Geologic and engineering evaluation of Seeligson's middle Frio gas reservoirs indicated that well-connected fluvial sandstones have been effectively drained by dense well and completion spacing (Ambrose and others, 1992).

Formation-evaluation techniques included the development of an interpretive scheme for identifying bypassed gas intervals that uses full-wave acoustic through-casing measurements in combination with a pulsed gamma-ray density-neutron log to obtain porosity and water saturation behind casing (Jirik and others, 1991). Completions in bypassed reservoirs had high initial production rates that are projected to yield an estimated return on investment that is favorable with even moderate gas price forecasts of $1.30 per Mcf.

In early 1990 Stratton field became the focus of the SGR's research effort in fluvial-dominated gas reservoirs (Levey and others, 1993a). Cooperation with Union Pacific Resources Co. (UPRC) in Stratton gas field initiated with a project cooperative well (UPRC Elliff No. 40),

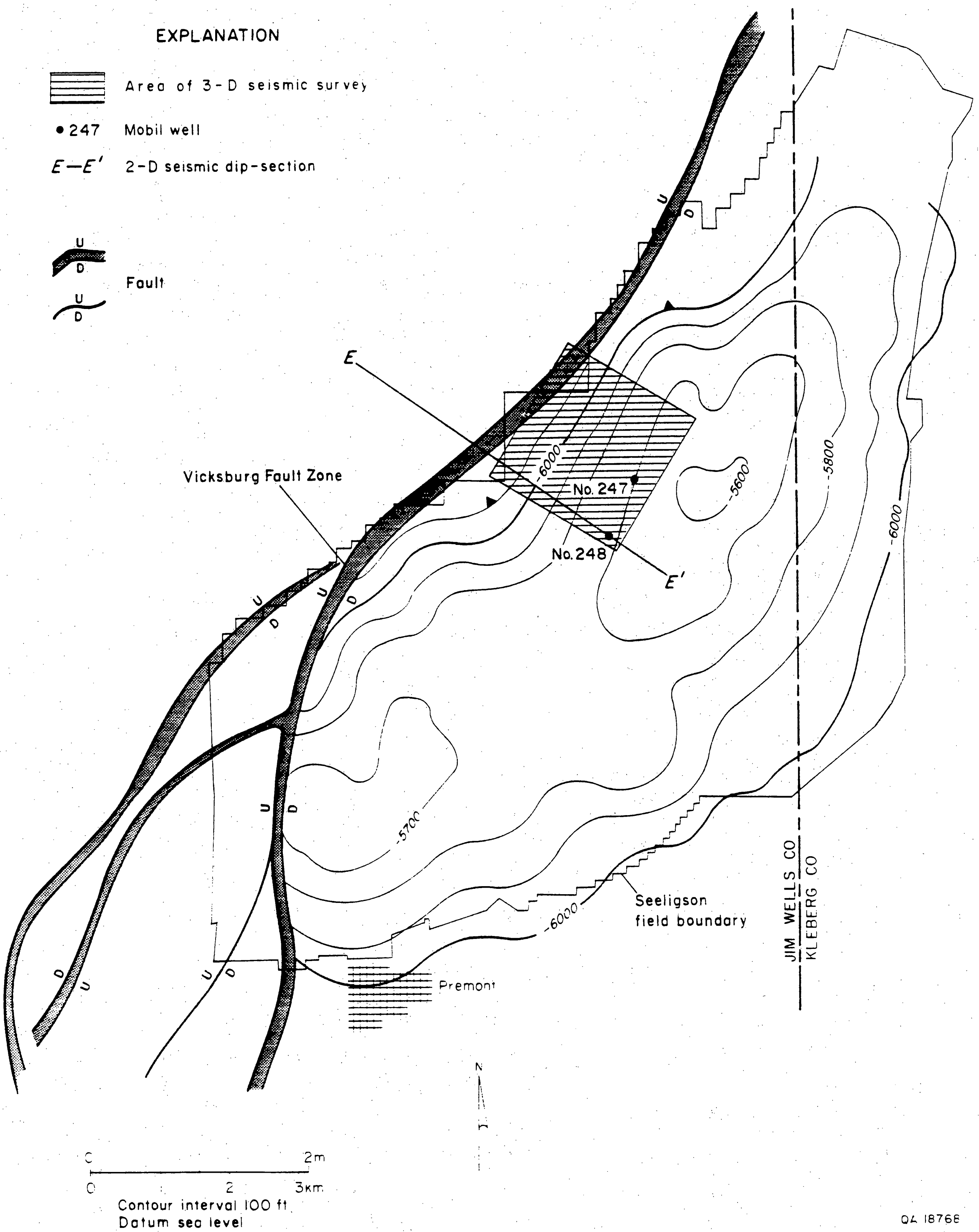


Figure 26. Structure map of Seeligson field, contoured on the *Textularia mississippiensis* (lower Frio) biozone. The principal growth fault offsets Vicksburg and Frio strata from 300 to 1,700 ft (91 to 518 m) and forms the western boundary of the field. Modified from Jirik and others (1989).

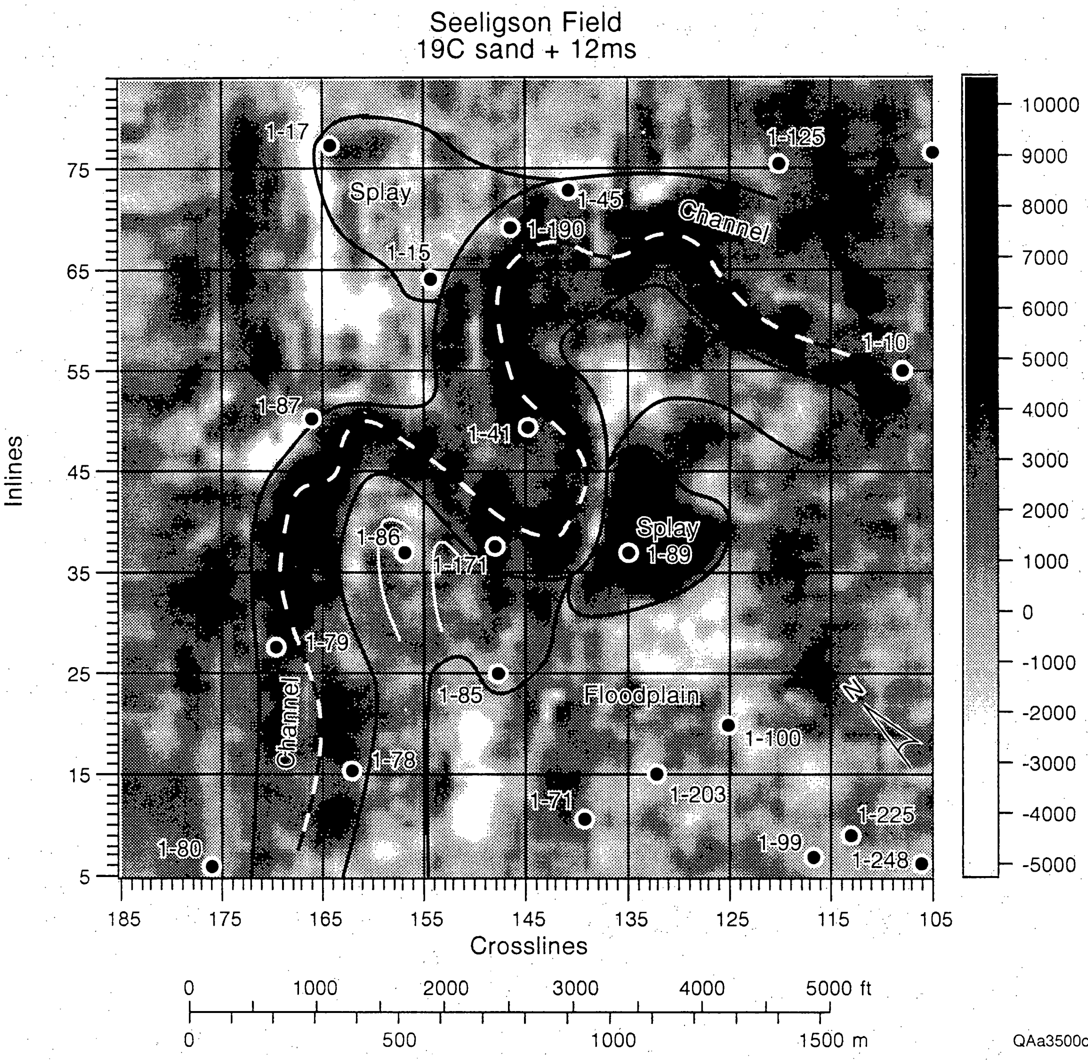


Figure 27. Seismic amplitude map of the upper Zone 19C genetic unit in north-central Seeligson field, indicating narrow (<1,000 ft [<305 m] wide), sinuous channel-fill deposits. (a) Net-sandstone-thickness contours superimposed from figure 22. (b) SP log facies superimposed from figure 24. Sinuosity is defined as the horizontal distance along the channel thalweg divided by the distance along the channel meanderbelt.

and data acquisition included wireline pressure testing, whole cores, open- and cased-hole logs, and both zero and far-offset VSP's.

Historical analysis of reserve growth across a large contiguous lease block in the south part of Stratton field (fig. 28) indicated that an aggressive infield drilling and recompletion campaign in this 50-year-old gas field resulted in more than 90 percent reserve replacement when adjusted for 40 years of production and development (fig. 29) (Levey and others, 1991; Sippel and Levey, 1991). Historical analysis of reserve additions indicated that the fluvial reservoirs less than 7,000 ft deep provided a screening technique for further geologic and engineering evaluation. Overall reserve growth achieved from the shallower, middle Frio reservoirs is superior to that obtained by completions in the deeper reservoirs in the lower Frio and Vicksburg (fig. 30), both on a total gas volume basis (fig. 31a) and on a per-completion comparison. Analysis of the reserve additions per completion indicates that the gas completions less than 7,000 ft (fig. 31b) added 379 MMcfg per completion (33 Bcf in 90 completions), compared with 250 MMcfg for completions greater than 7,000 ft (fig. 31c) (15 Bcf in 59 completions). The contrast in gas production between reserves shallower than 7,000 ft and those deeper than 7,000 ft coincides with a major change in the structural and depositional setting in the study area. The middle Frio Formation reservoirs (<7,000 ft) are in fluvially dominated reservoirs; in contrast, the lower Frio and Vicksburg reservoirs (>7,000 ft) are in a predominantly deltaic setting that approaches the top of geopressure or requires penetration into geopressured intervals (fig. 30). In addition, structurally rotated fault blocks are encountered in the lower Frio and Vicksburg below 7,000 ft. It is well recognized that drilling costs almost always increase when (1) drilling deeper wells, (2) penetrating geopressured intervals, and (3) drilling in structurally deformed intervals. Estimates of incremental recoverable gas range from 0.73 to 2.6 Bcf per reservoir completion. Deeper pool drilling targeted for the deltaic reservoirs in the Vicksburg also led to recognition of the potential for higher density development of shallower intervals.

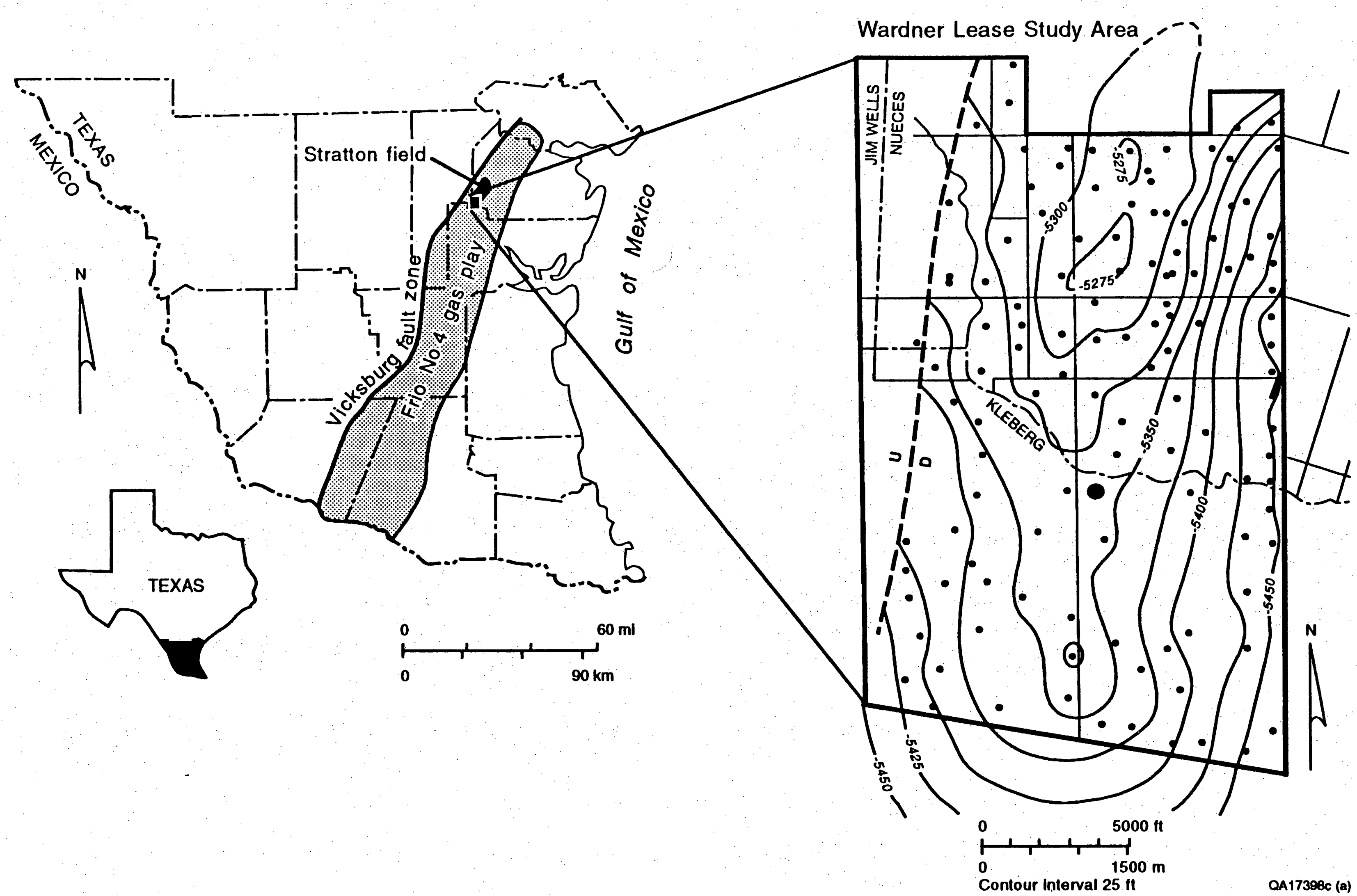


Figure 28. Subsea structural horizon in the middle Frio showing the gentle structural domal closure that is typical of reservoir intervals in the middle Frio Formation.

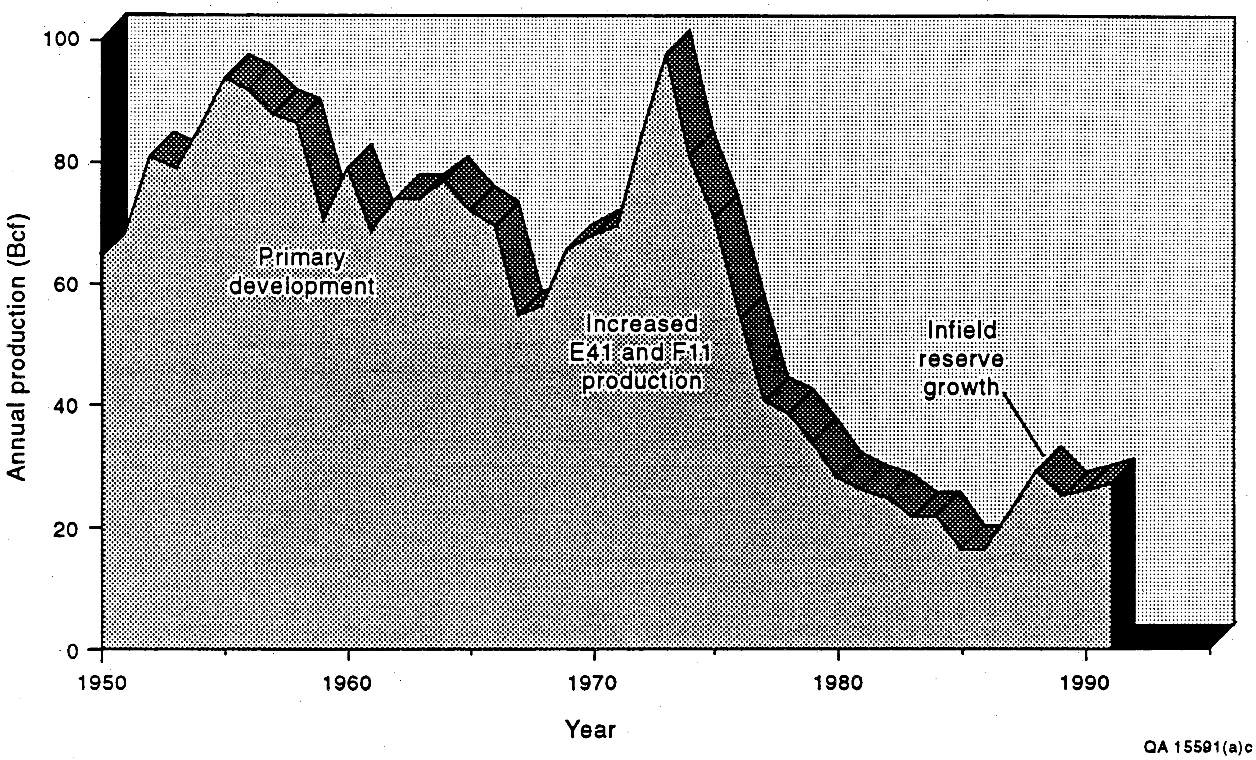


Figure 29. Annual gas production of Stratton field from 1940 to 1992 showing increased annual production associated with infield drilling and recompletions.

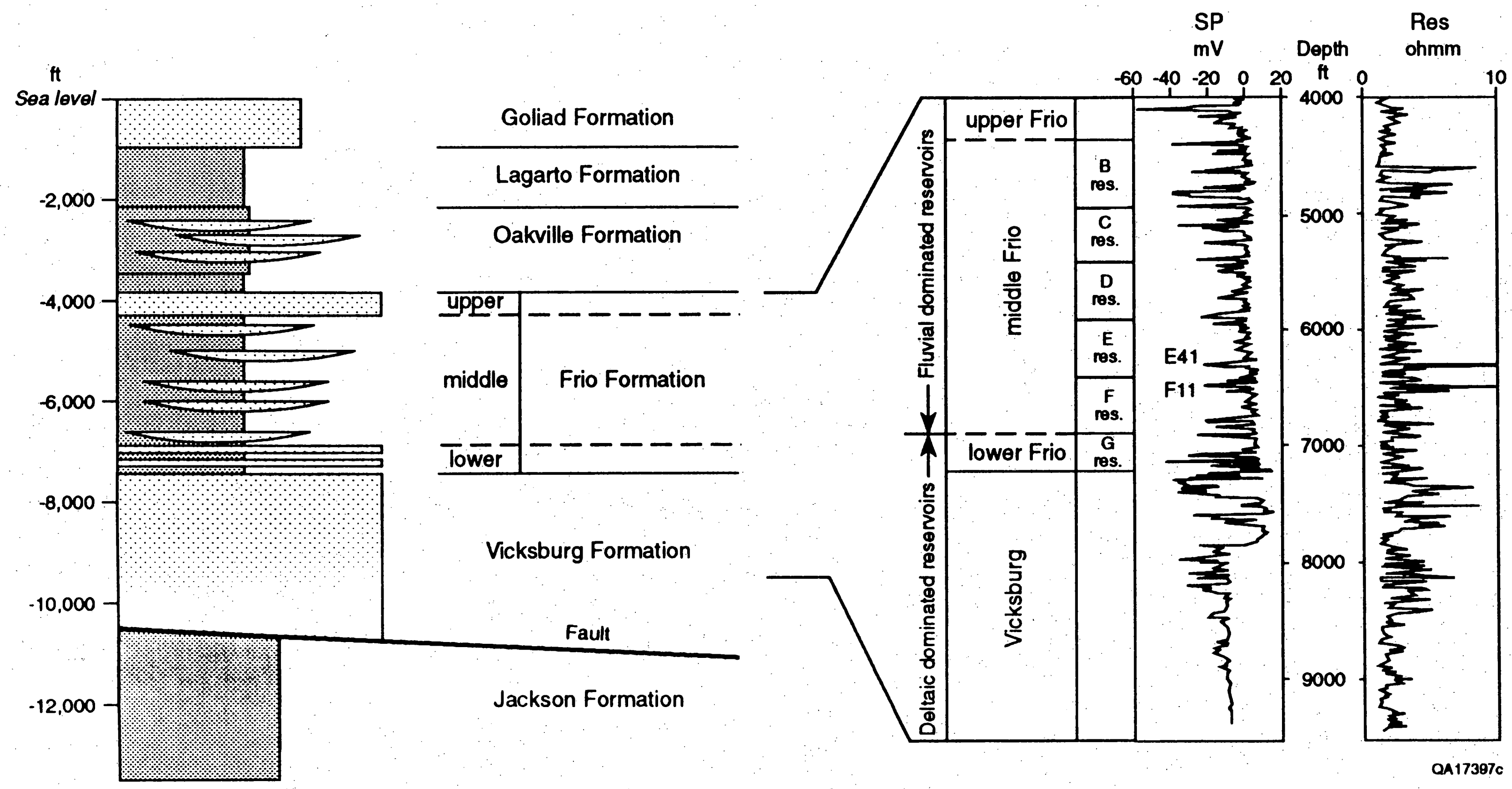
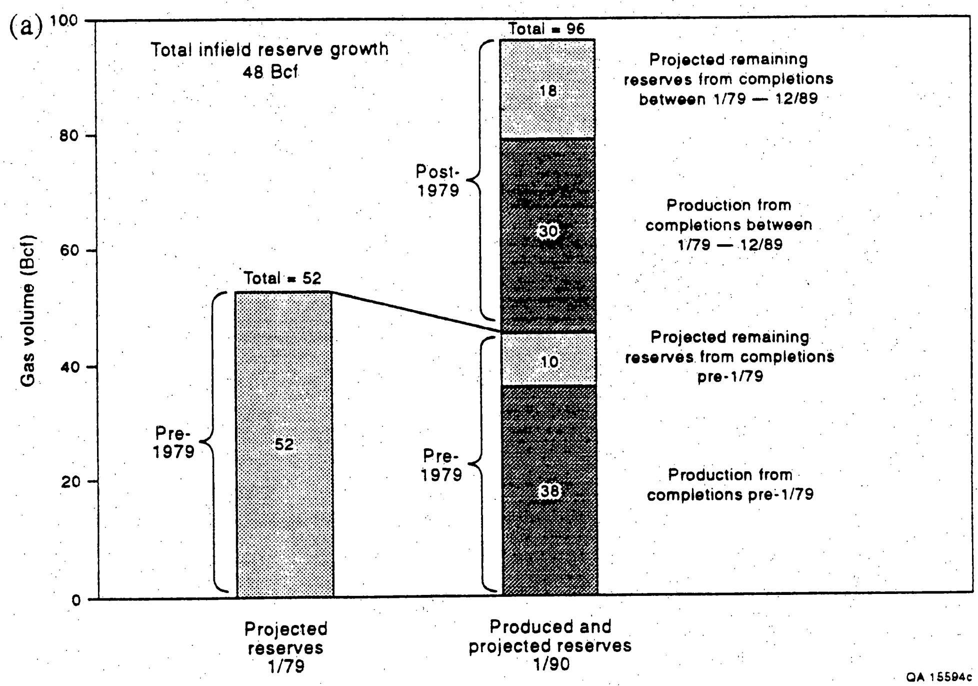


Figure 30. Type well log (spontaneous profile and resistivity) from the Wardner lease study area showing the reservoir nomenclature in the Frio and Vicksburg Formations.



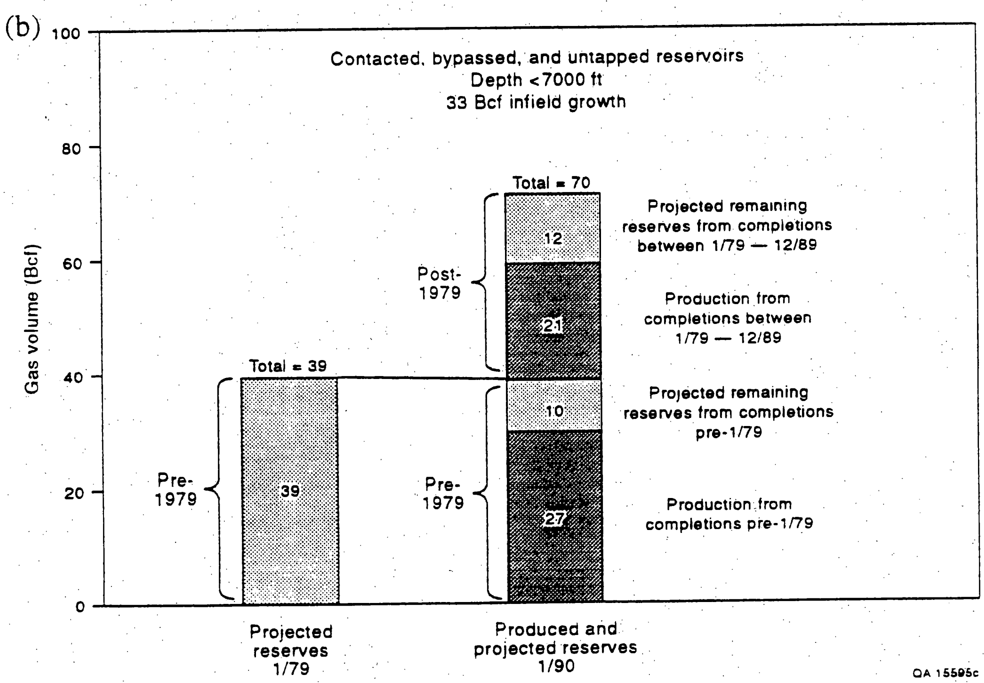


Figure 31. (a) Total gas volume for all completions and (b) gas volume for completions above 7,000 ft in the Wardner lease study area.

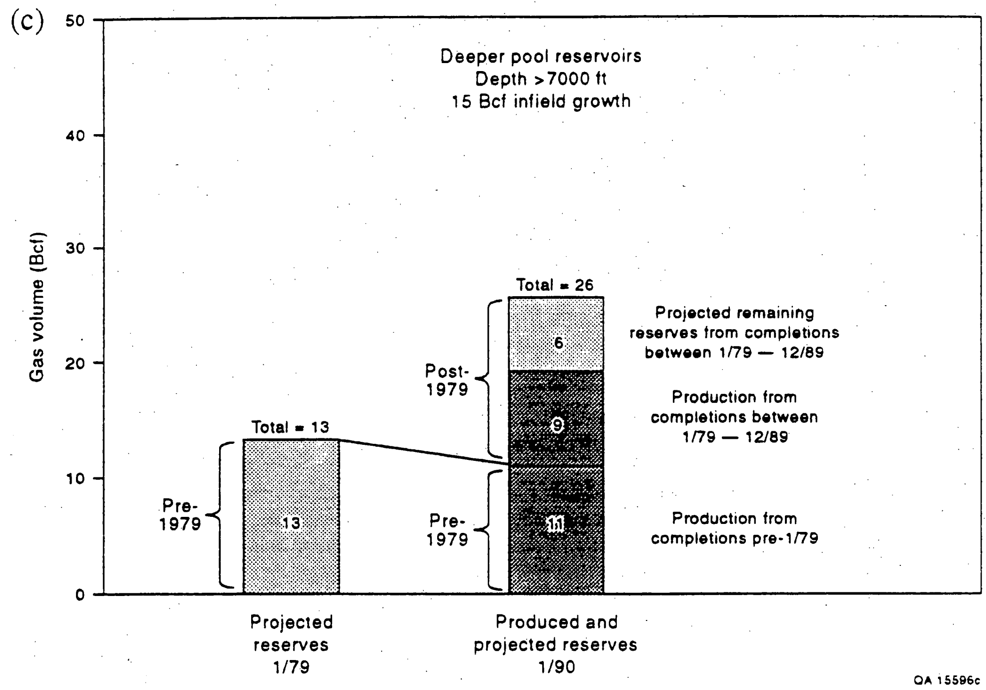


Figure 31. (c) Gas volume for completions below 7,000 ft in the Wardner lease study area.

In May 1991 the SGR project initiated a three-phase test program to calibrate, identify, and potentially predict additional secondary gas resources still remaining in fluvial reservoirs in the middle Frio Formation. Close cooperation by the field operator with the SGR project has permitted access to more than 50 producing and temporarily abandoned gas wells across Stratton gas field for engineering testing, logging, and seismic data acquisition. Reservoir engineering research included a combination of static pressure tests, single-well transient tests, and multiple-well interference tests within four reservoir intervals across a large portion of the field. Differences in pressure of 500 psi in reservoirs having conventional permeability were measured at 40- to 80-acre completion spacing, even in regions of the field that have been producing for more than 20 years.

An important product of SGR research project is a compartmented reservoir model, which is a user-friendly, microcomputer-based program designed to evaluate typical production information and detect behavior in a compartmented reservoir. This newly developed compartment model simulator (called the Gas-Wizard) is a relatively simple mathematical model which, using only a few key engineering parameters, is capable of reproducing the dominant features of observed pressure and production rate histories in most conventional permeability gas reservoirs (Lord and Collins, 1991). This simulator has proved valuable in assessing compartmented reservoir character based solely on production and pressure histories of wells in such reservoirs. Engineering clues for detecting compartmented reservoir behavior include the rate-time diagnostic plots that can be used to look for evidence of pressure support from a secondary volume to the primary volume produced by the well bore. The compartment model describes heterogeneous reservoir function as a set of tanklike compartments having leaky barriers that separate compartments from wells that produce from these compartments, which are described by simple quadratic inflow relationships (fig. 32). The simulator focuses on modeling function, as opposed to modeling anatomy, or structure, of reservoirs.

The reservoir is conceptualized as being composed of one or more porous, permeable compartments, with flow between compartments through low-permeability barriers (Collins and

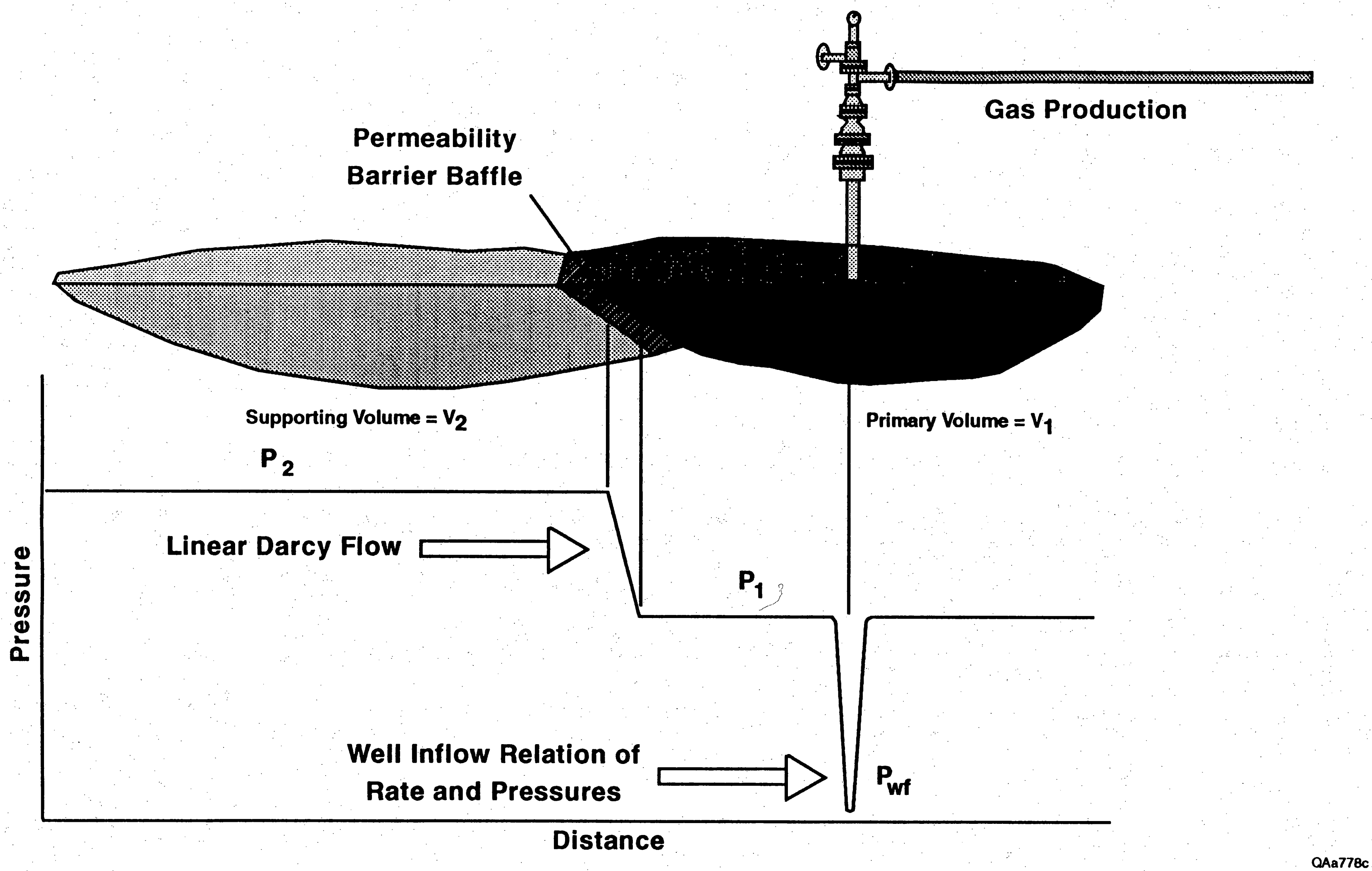


Figure 32. Compartment model that describes heterogeneous reservoir function as a set of tank-like compartments having leaky barriers that separate compartments from wells that produce from these compartments.

Lord, 1992). A barrier between compartments can be varied from impermeable to highly permeable. Production is allowed from any compartment. Typically a well is analyzed with two compartments representing primary and supporting drainage volumes, but it is important to realize that the reservoir is often more complex and that effective support volumes may not be contiguous (fig. 33). The model is designed to predict the history of average pressures for all compartments for specified production-rate or pressure drawdown histories of a well, or wells, completed in the reservoir. Fixed parameters are the pore volumes of the compartments, transmissibilities of barriers between compartments, specific gravity of the gas, initial reservoir pressure and temperature, and two inflow parameters that define the flow performance of the well in that compartment.

Inflow performance relationships are the basis of this compartmented-gas-reservoir simulator. The model uses field-specific fixed input parameters such as gas gravity, temperature, and initial pressure. The user adjusts for compartment pore volumes, suspected barrier transmissibilities, and well-inflow performance parameters. Either rate or well-bore pressure histories are compared with the model output of pressure, rate, and/or cumulative production by well. The model is tuned until a good match is obtained and a projected depletion history is generated (fig. 34).

Field data can be history-matched by adjusting model parameters, such as compartment pore volumes and barrier transmissibility, until the model response agrees with the observed field data. The parameters from the model history-match characterize the reservoir structure. Specifically, a determination of compartment volumes and barrier effectiveness in limiting gas flow are useful in evaluating infield reserve growth potential and development strategies. Combining the rate and pressure histories of a well in a simple-to-use model allows identification and quantification of compartmented reservoir behavior when traditional rate-time and pressure-cumulative methods may be ambiguous.

Fluvial reservoirs at Stratton field (Kerr and Jirik, 1990) are ranked in character from less to more compartmented as (1) thick, broad-channel amalgamated sandstones (laterally stacked),

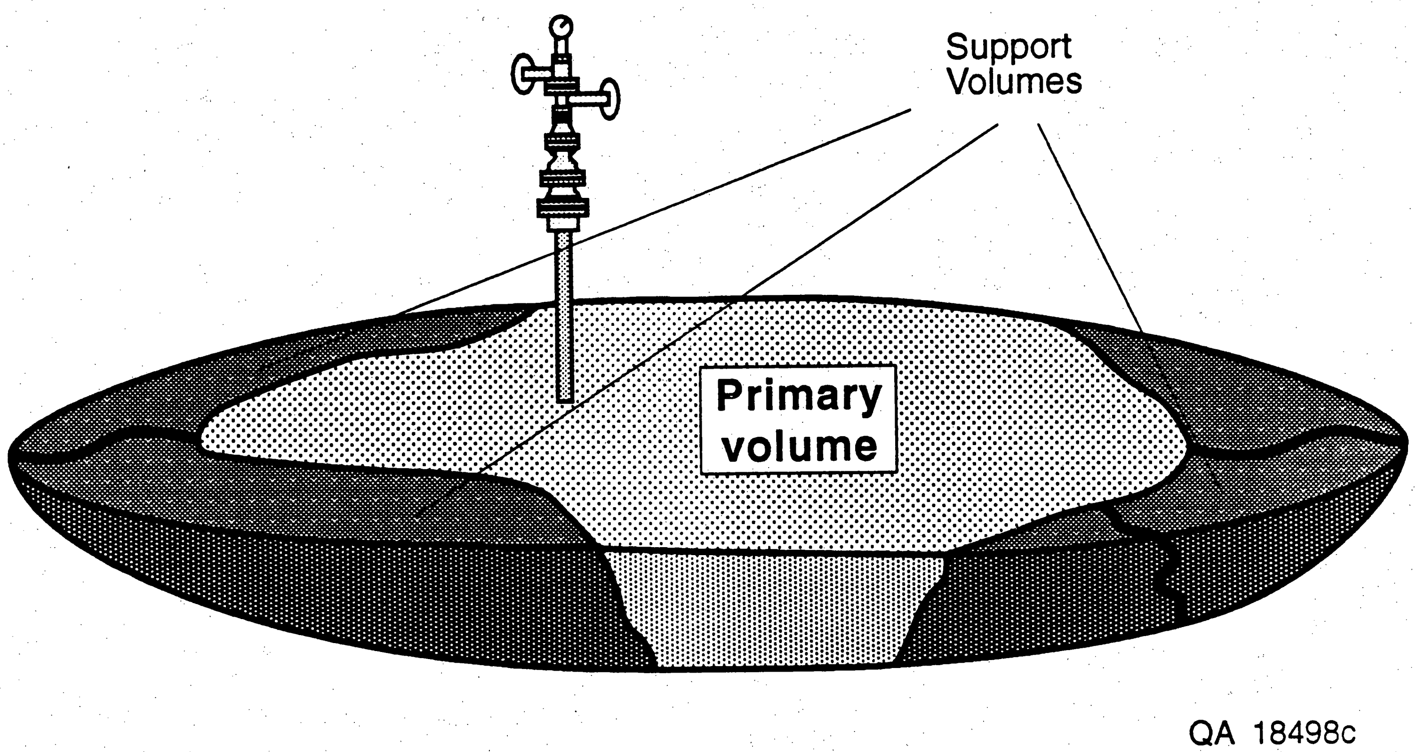


Figure 33. Diagram showing concept of primary and supporting drainage volumes and showing that effective support volumes may not be contiguous.

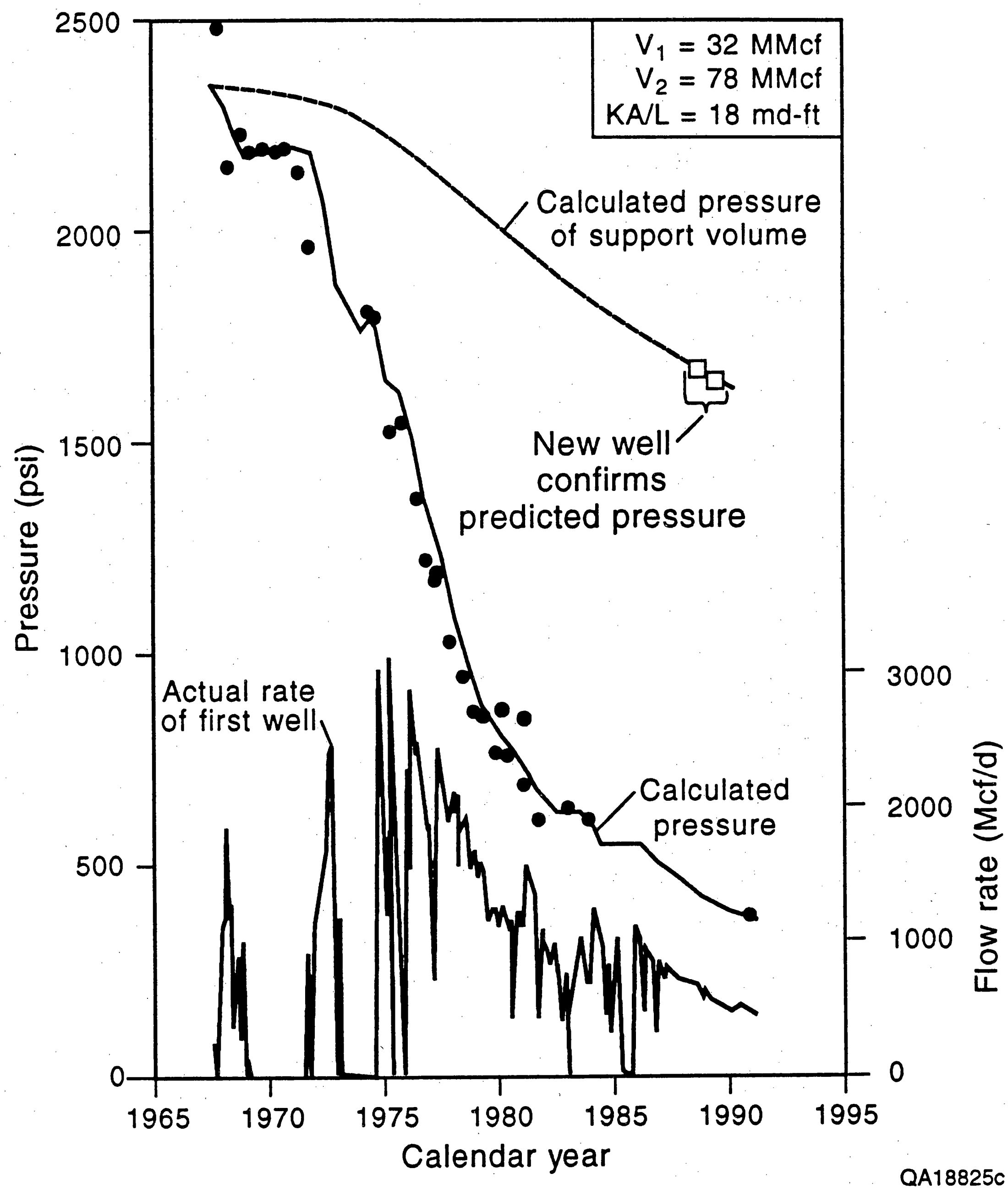


Figure 34. An example of a pressure history match for the Wardner No. 80 in the F-39 reservoir interval using the G-WIZ compartmented gas reservoir simulator.

(2) mixed-load channel sandstones, and (3) thin, narrow-channel dispersed sandstones (vertically stacked). The progression of compartmented fluvial reservoir architecture is diagrammatically shown in figure 35. The most compartmented gas reservoirs are the narrow fluvial-channel sandstones. The least compartmented reservoirs are the thick sandstones deposited in broad channel systems.

The Gas-Wizard model was used to define compartment size distributions from fluvial-dominated reservoirs in the middle Frio Formation. Three classes of reservoir compartment size distribution were delineated from the spectrum of fluvial reservoirs. Each reservoir group exhibits a log-normal distribution of primary drained pore volume (fig. 36). Stochastic modeling is used to relate compartment size to well spacing. Building a stochastic modeling process with data and output from the Gas-Wizard simulator defined an approach to understanding effective well spacing in different classes of reservoir compartment size distributions. The three classes characterized by large, medium, or small reservoir compartment sizes that were delineated from 10 groups of Frio reservoirs are stacked over a 2,000-ft interval dominated by fluvial reservoirs in Stratton-Agua Dulce field (fig. 29). Producing rate and static pressure data were used to determine the three fundamental reservoir parameters: primary drained pore volume, supporting pore volume, and barrier transmissibility. Statistical distributions of the primary pore volume and transmissibility were found to be closely approximated by a log-normal distribution in each of the 10 reservoir groups. Forward stochastic modeling of gas recovery from the three compartment size classes indicates that well spacing of 340, 200, and 60 acres (or less) provides maximum gas contact efficiency (fig. 37). The stochastic technique generates realizations of fluvial reservoirs having internal compartments with intervening barriers. Simulations of multiple reservoir realizations honoring statistical distributions determined from reservoir data yield a unique probability distribution of expected gas recovery. Recovery factors were evaluated for different well spacing and completion timing scenarios. By this method, statistical predictions of recovery are generated for each of the three classes representing a spectrum of fluvial reservoirs. For example, in the small compartment size class, incremental recovery

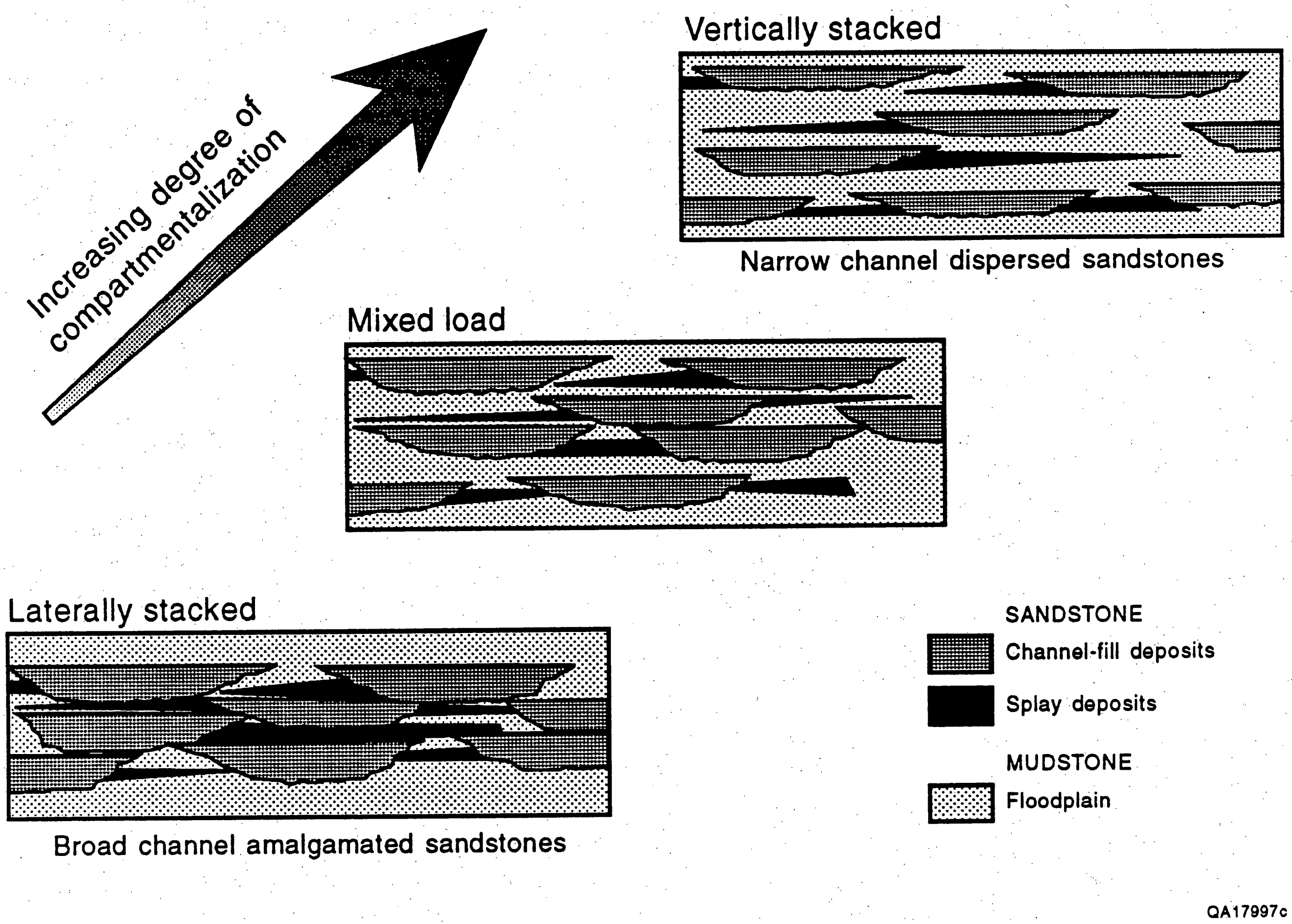


Figure 35. Schematic diagram illustrating the fluvial architectural continuum (modified from Kerr and Jirik, 1990).

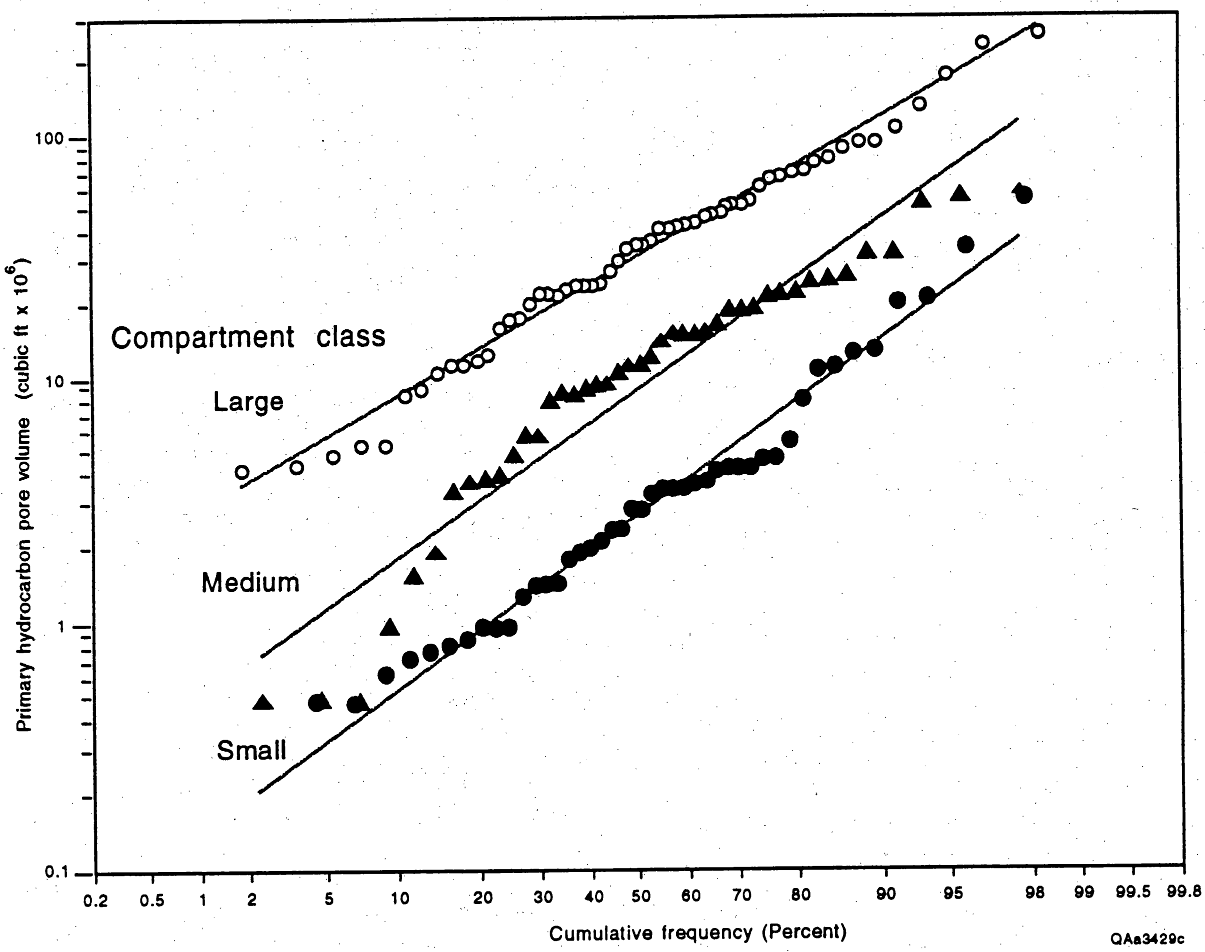


Figure 36. Cumulative frequency distribution of primary pore volume for the three compartment size classes in Stratton field.

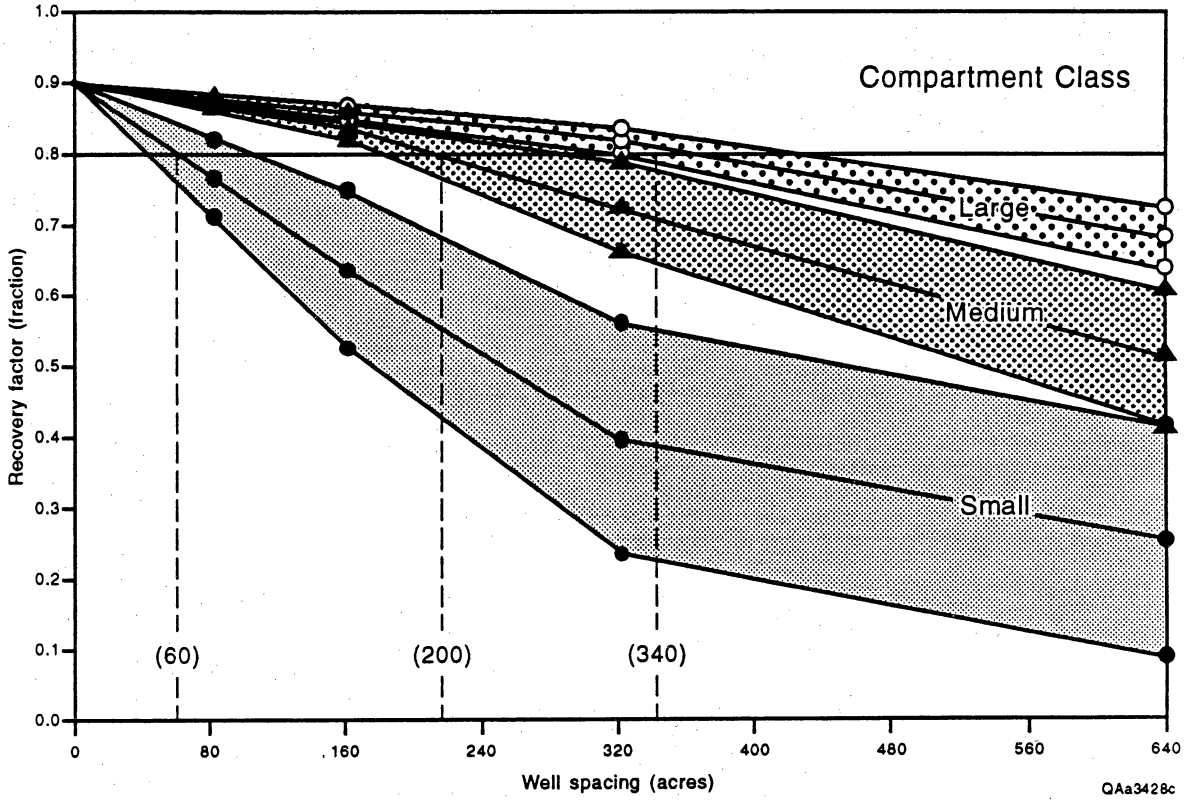


Figure 37. Recovery factor and predicted gas recoveries versus well spacing for large, medium, and small compartment size classes.

potential of 24 percent is predicted by decreasing completion spacing from 320 to 160 acres (fig. 38). These effective gas recovery well spacing correlations should be transferable to other fields with similar fluvial facies and reservoir architecture.

A strong emphasis was placed on the evaluation of geophysical techniques applied to secondary gas recovery. Three-dimensional reflection seismic imaging is the most rigorous methodology developed to date for remotely mapping reservoir heterogeneity. Delineation of reservoir topology and the identification of reservoir compartments can be achieved using carefully calibrated three-dimensional seismic.

Analysis of three-dimensional seismic imagery in a 7.5-mi^2 grid, coincident with multiple well tests in Stratton field, was used to investigate reservoir compartment boundaries identified by other SGR techniques. Flattening and seiscrop slicing above and below reference horizons were used to reveal depositional topography and to determine the extent of structural influence on reservoir horizons. Seismic time-to-depth calibration of seismic thin-bed intervals was achieved by careful attention to detail during three-dimensional data acquisition and processing and by using high-quality zero-offset VSP data to define exactly where thin bed time windows exist in the surface-recorded seismic responses. Many Stratton reservoirs are only 10 to 15 ft thick and occur within seismic time windows as thin as 2 to 4 ms. Careful calibration is required to accurately locate these time windows in the reflection waveforms. In Stratton field, three-dimensional seismic imagery has revealed fluvial channels as narrow as 200 ft and as thin as 10 ft that are visible at depths as low as 6,800 ft (fig. 39). Reservoir compartment boundaries can be imaged within, or adjacent to, these channels.

In many cases the depositional topology revealed in these thin-bed seismic images clearly indicates where a compartment boundary should be positioned between well control. At other reservoir levels, where either geologic or engineering data indicate a compartment boundary, the boundary is not obvious in the seismically revealed depositional topography. In these latter instances, the seismic image usually shows a semicontinuous depositional unit, which implies that this second type of compartment boundary does not significantly affect the reflected

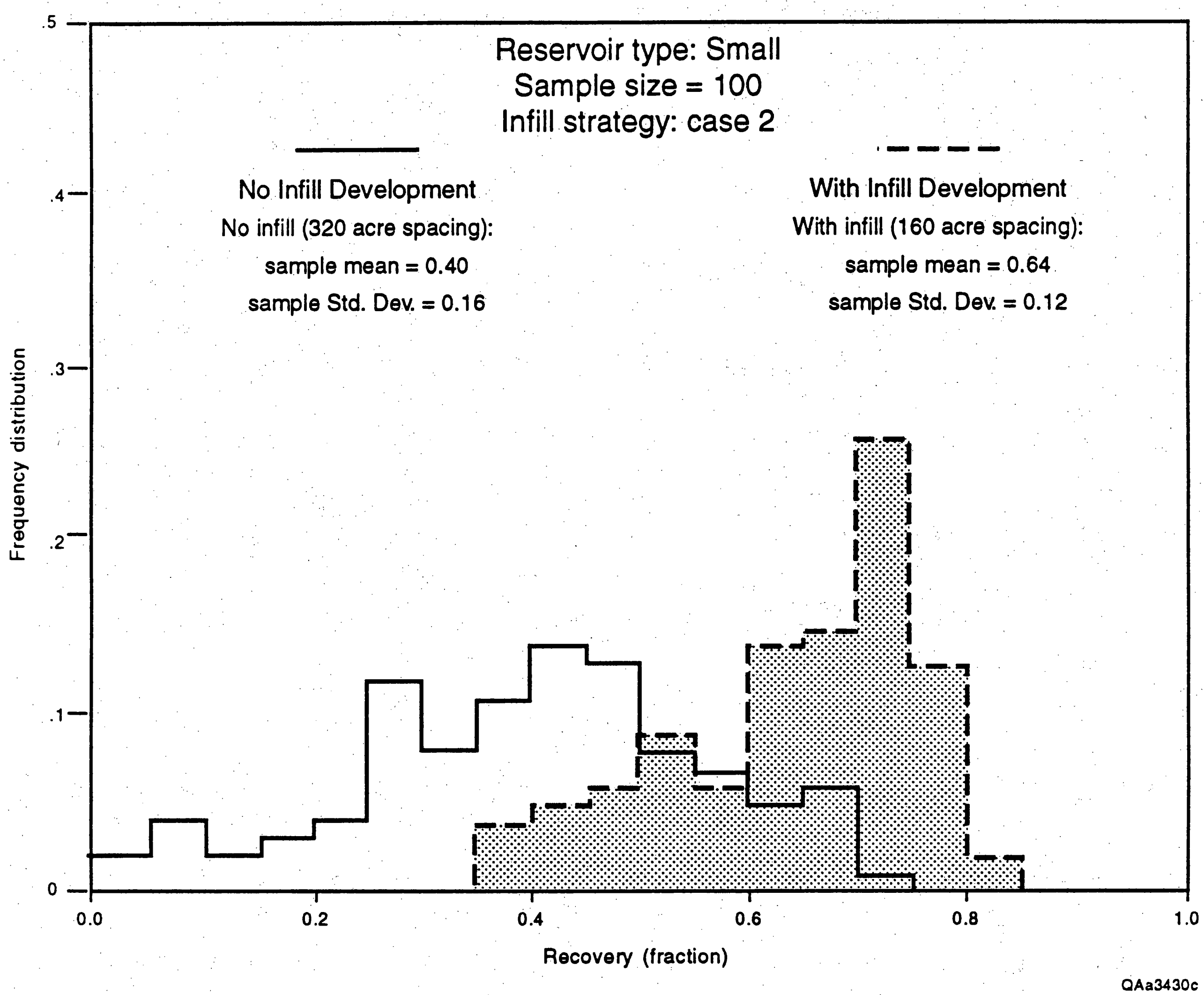


Figure 38. Frequency distribution illustrating effect of completion schedule on gas recovery for the small compartment size class.

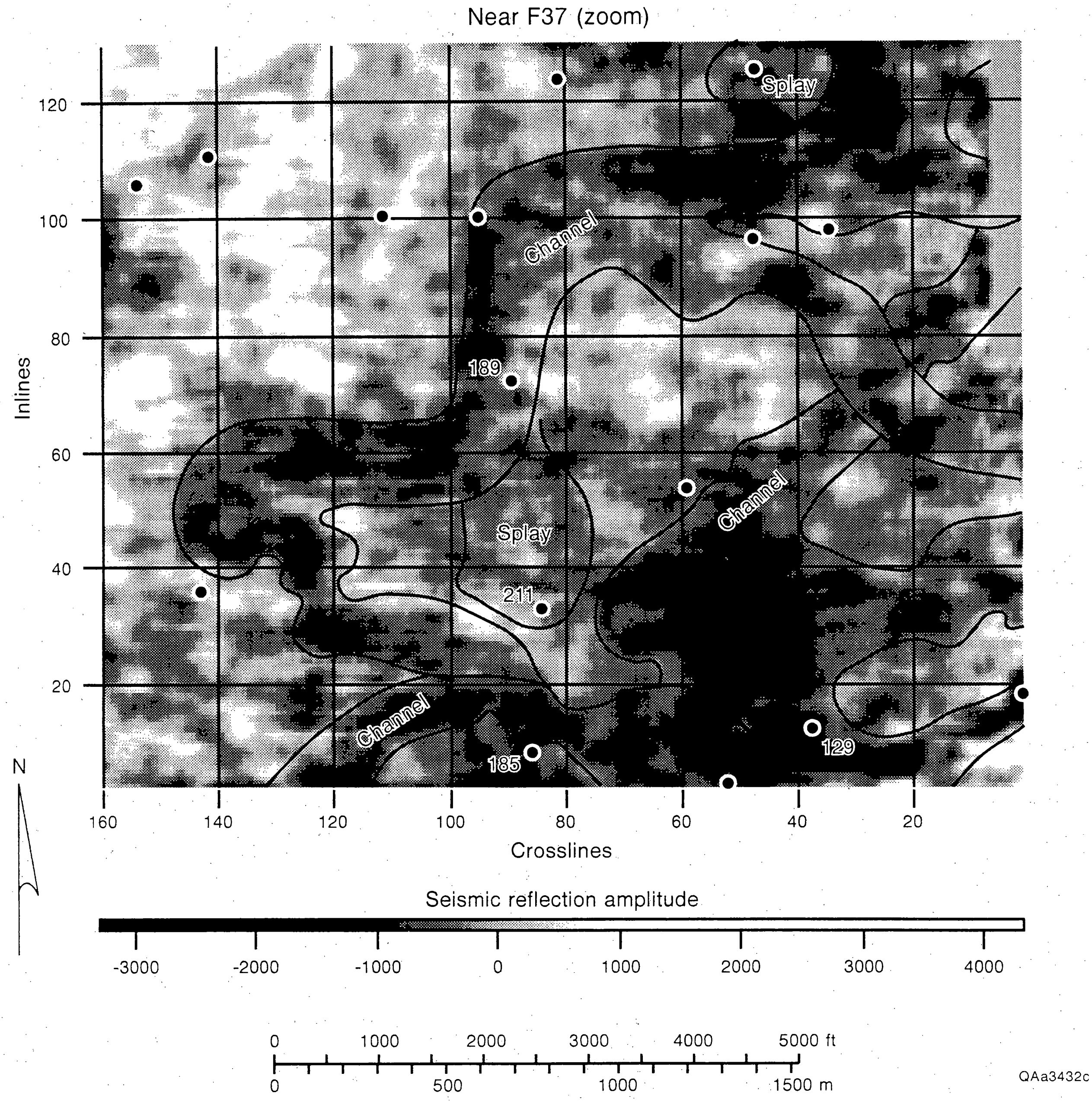


Figure 39. Seiscrop map of the F-37 reservoir in the south part of the Wardner lease 3-D data volume.

seismic wavefield. Although many subtle, fluvially deposited compartment boundaries are revealed in these three-dimensional seismic images, some boundaries cannot be seismically imaged due to minimal differences in the acoustic impedance of reservoir and nonreservoir facies and must be located by stratigraphically correlating geologic data, analyzing production histories, or performing well-pressure tests. In all cases, the interpretation of three-dimensional images at 10 reservoir levels in Stratton gas field (B46, C35, C38, D11, D35, E49, F11, F20-25, F37, and F39) provided more information about the distribution of reservoir facies in the interwell spaces than could be obtained by the standard procedure of extrapolating only geologic and engineering data from control wells.

The cost of three-dimensional seismic acquisition and processing continues to diminish and, depending on the size of the survey and the nature of the target objectives, the acquisition cost of onshore three-dimensional seismic coverage can often be only a few tens of thousands of dollars per square mile. Because of this relatively low cost and the potentially significant insight such data can provide about reservoir heterogeneity, modern reservoir management strategy should emphasize three-dimensional seismic activity or should, as a minimum, include an economic analysis of the benefits of three-dimensional seismic imaging on infield reserve growth. Three-dimensional seismic provides a cost-effective tool for imaging interwell space.

CASE STUDIES

Two case studies, or mini-evaluation projects, were conducted to demonstrate the application of SGR concepts and technology by independent operators (Levey and others, 1993b). The SGR project, in cooperation with operator-initiated redevelopment in two fields that are over 50 years old, evaluated the application and benefit of SGR concepts and technologies. Integrated geologic, engineering, and petrophysical analysis of 21 reservoirs defined an OGIP of 37 Bcf, of which 28 Bcf is technically recoverable. Economically recoverable gas reserves were estimated at 10 Bcf in two study areas totaling 2,300 acres. The reservoirs are normally pressured, primarily depletion-drive reservoirs, at moderate depths between 3,700 and 7,000 ft.

In case I, secondary gas resources occur in thin-bedded barrier/strandplain deposits. By using the state-of-the-art induction array tool, thin-bed high-productivity reservoirs can be better identified than by using conventional electrical and induction logs. Detailed stratigraphic analysis of multiple thin-bed intervals in combination with resistivity cutoffs and spontaneous potential ratios provided a means of identifying locations for enhancing the operator's ability to recover these secondary gas resources. In case II, secondary resources were defined in fluvial depositional reservoir facies segmented by structural compartments and affected by stratigraphic variability and diagenesis. Integrated formation evaluation using high-resolution logging, spectral gamma-ray measurements, wireline pressure tests, and core analysis were effective in identifying additional gas resources. Gas reservoirs in fluvial channel sandstones oriented perpendicular to fault trends also affect the operational strategy required to maximize recovery.

For cases I and II, the average ultimate recovery is 400 and 260 MMcf per completion, respectively. The total cost to develop and produce SGR reserves is projected at $0.58 (case I) and $0.83 (case II) per Mcf. The primary difference between the two case studies is that the case II area has smaller reservoir compartments caused by faulting and depositional and diagenetic effects on reservoir productivity. As a consequence of smaller compartment size, development costs are higher due to the requirement of more wells and recompletions to access the SGR resource. Evaluation of 21 reservoirs in 2 mature onshore Gulf Coast gas fields demonstrates that small independent gas operators can effectively apply SGR concepts to economically develop bypassed, untapped, and incompletely drained reservoirs to maximize secondary natural gas recovery. These mini-evaluations demonstrate the feasibility of using SGR approaches for converting technically recoverable resources into economically producible reserves at low to moderate cost.

TECHNOLOGY TRANSFER

One of the major challenges facing many research programs is the successful dissemination of technological information and the enhanced utilization of research results. During the course of this joint venture research program, the Bureau of Economic Geology, as the lead technological contractor, has made an extensive effort to communicate research results to industry, academia, governmental organizations, and the general scientific community. From September 1988 to June 1993, 7 GRI topical reports, 28 technical articles, 17 published abstracts, 91 public addresses, 8 short courses, 2 workshops, several half-day seminars, and 1 geological circular published by the Bureau have been used to disseminate research results from this multiyear and multidisciplinary project. Four additional Bureau publications are in preparation.

In addition to these publications, the members of the SGR research staff have produced several documents that are not formal publications, including slide and overhead presentations, geologic descriptions and other reports describing cores, maps, pressure and production reports collected in SGR cooperative wells, and affiliated data analysis. These reports and documents have been issued to other DOE and GRI subcontractors, project advisory groups, companies, and interested parties involved with natural gas resources.

Because of past and ongoing natural gas research projects at the Bureau, numerous inquiries come from both major domestic companies and small independent gas operators. These inquiries request information often directly related to the application of research results to enhance or develop gas production. These inquiries are often answered by sending project publications and referencing future publications and upcoming workshops, short courses, technical presentations, or meetings. On-site visits provide another means of direct contact between researchers and gas operators.

ANNOTATED LIST AND SUMMARY OF PROJECT TOPICAL REPORTS

Secondary natural gas recovery: reservoir heterogeneity and potential for reserve growth through infield drilling: an example from McAllen Ranch field, Hidalgo County, Texas: by Langford, R. P., Wermund, E. G., Grigsby, J. D., Guevara, E. H., Zinke, S. K., Collins, R. E., Sippel, M. A., Hower, T. L., Lord, M. E., Kocberber, S., and Howard, W. E., 1992, The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the Gas Research Institute under contract no. 5088-212-1718 and the U.S. Department of Energy under contract no. DE-FG21-88MC25031, Report No. GRI-92/0112, 289 p.

The overall objective of this report is to describe reservoir heterogeneities within a representative mature gas reservoir of the Oligocene Vicksburg Formation (McAllen Ranch field) in South Texas and to determine how aspects of reservoir heterogeneity affect potential reserves remaining in the reservoir. There are two primary objectives: (1) to describe the controls on and architecture of depositional and diagenetic heterogeneities that may segment gas reservoirs within the field and (2) to determine if these heterogeneities are effective in restricting the flow of gas so that gas reserves may remain incompletely drained or untapped. Our analysis of public production data (Dwight's Energydata) indicates that new infield wells in the Vicksburg S reservoir have accounted for a 27.4-Bcf increase in reserves between 1980 and 1990. Additionally, more than 100 Bcf of reserves has been added through new wells drilled between 1988 and 1991. Several recompletions are suggested in this report. During compilation of the report, three of those recompletions were performed and resulted in a reserve increase we estimate at 1.125 Bcf.

Most of the McAllen Ranch Vicksburg S reserve increases are due to three factors: (1) a geological reinterpretation of the S reservoir in the B lease of McAllen Ranch field has stimulated infield step-out development of the Vicksburg S reservoir; (2) improved hydraulic fracture technology, the development of staged fractures, has allowed successive completion and commingling of several reservoir sandstones; and (3) regulatory consolidation of previously distinct reservoirs has allowed commingling of reservoirs and thus completion of intervals that would not be economic in isolation.

Within this framework of successful infield development by the working interest partners at McAllen Ranch field, we have derived the following recommendations for maximizing recovery from similar deep Vicksburg deltaic reservoirs.

We consider reinterpretation of reservoir geometry and areal extent to be the most important contributor to reserve additions within the South Texas Vicksburg deltaic sandstones. The McAllen Ranch Vicksburg S reservoir in the B area provides an excellent example of reserve additions, and more than 100 Bcf of proven reserves have been added since 1988 (Hill and others, 1991). Shell Western Exploration and Production, Inc., recorrelated reservoir sandstones and eliminated a postulated fault, thereby extending the previously assumed limits of the reservoir.

Regulatory changes that permit larger completion intervals and thus allow more sandstones to be completed at closer spacing allow significant infield reserve increases. Operators of Vicksburg gas production commonly produce only the most potentially productive reservoir intervals because of limited well-bore lifespan. Recompletions within the Vicksburg are often difficult, and gas resources that are uneconomic with new wells, but that would be economic on recompletion, may be lost. Reservoir consolidation in the B area of McAllen Ranch field has stimulated recompletions and added significantly to production.

Distributary-channel-fill sandstones are the best candidates for containing incremental reserves because they are laterally discontinuous and they predominate in areas where numerous reservoir sandstones are stacked. In other gas fields, secondary recovery efforts should target the proximal portions of deltaic packages. Delta-front sandstones have the poorest potential for large reserve increments because of their lateral continuity and relatively simple stratigraphy.

The most important variable in the Vicksburg S reservoir heterogeneity is diagenesis, which creates variable drainage radii for different sandstones in the same well. Diffuse, diagenetically controlled zones of low permeability may be the most important factors restricting flow between wells. Variable drainage radii result in unrecognized and unproduced reserves between existing wells, especially where completion spacing within individual sandstones is nonuniform. In the B area, faults are not likely to be the primary barriers to gas flow because faults were not inferred from high-quality three-dimensional seismic images between the key wells used in this study (Hill and others, 1991).

The microresistivity log from the dipmeter is an effective tool for determining both depositional and diagenetic facies within the S reservoir. With additional microresistivity logs, cements could be mapped through the reservoir, allowing better prediction of "sweet spots" and variation of permeability.

The effects of faulting in creating the observed compartmentalization of the reservoir are difficult to separate from depositional effects in structurally complex Vicksburg reservoirs. Faulting as a cause of reservoir compartmentalization must be considered in addition to depositional heterogeneity. Likewise, the effects of completion in numerous separate flow units make accurate determination of the sources of production impossible. However, variation in the extent and quality of hydraulic fractures does not seem to have been a major factor before 1988. Shell Western Exploration and Production, Inc., has recently instituted a new fracturing program that appears to them to have improved production.

Wells exhibit significant increases in production rates for a very long time after a period of curtailed production. This increase was initially thought to be due solely to "recharge" by flow across low-permeability barriers from neighboring, untapped compartments, but model studies disproved this conjecture. The increased rate is now attributed to time-delayed compaction, or creep, of the overburden as pressure support is removed by fluid production from the overpressured reservoir.

A finite-element model of the S_4 sandstone in the S reservoir supports the hypothesis that barriers to gas flow may exist between wells at 80-acre spacing within the B lease study area. Analysis of production and pressures indicates that at the current 80-acre spacing significant reserves do not exist between completions. However, when there are holes in the completion pattern, producible reserves remain untapped. During compilation of this report we suggested the recompletion of several wells in the B area. Three of these wells (B-8, B-12, and B-15) have been recompleted, resulting in an estimated reserve increase of 1.125 Bcf.

The research required integrated geological, petrophysical, and engineering efforts to determine reservoir heterogeneity and potential infield reserve additions. More accurate interpretations of depositional systems and stratigraphic relations were used to define the distribution of sandstones and their internal heterogeneities. These data were used to assess the most likely targets for incremental gas recovery. Petrophysical analysis of data gathered from well logs and cores was used to determine the porosities within reservoir sandstones. Geometries derived from geological analysis were used along with porosity data to determine the gas remaining in the reservoir. Finally, production data and wireline pressure test data were used to model long-term pressure interference to demonstrate the existence of permeability barriers. The combination of geological, petrophysical, and engineering data was used to predict the distribution of volumes of undrained natural gas.

The S reservoir within McAllen Ranch field was selected for study because of availability of seismic data and evidence of lack of communication between wells. Two wells, the McAllen B-17 and B-18, drilled by Shell Western Exploration and Production, Inc., were cored and logged as part of a cooperative data acquisition program. Offset vertical seismic profiles flanking the two wells were acquired.

A detailed stratigraphy was established for the S reservoir, allowing its division into six genetic components. Structural maps and cross sections, along with net-sandstone and facies maps, allowed interpretation of the depositional environment within the S reservoir sandstones. Net-sandstone maps, along with detailed stratigraphic correlation, were used to carefully describe the component sandstones of the S reservoir and the heterogeneities that could potentially obstruct the flow of gas.

Detailed log suites acquired from Shell Western Exploration and Production, Inc., and obtained through the cooperative drilling program were used to obtain porosity and water saturation estimates within the reservoir. Because shale grain densities in the Vicksburg are much the same as sand grain densities, no large correction was necessary to match measured core porosities. However, because the clays have cation exchange capacities, it was necessary to use a Waxman-Smits model to obtain results that matched water saturations estimated from capillary pressure measurements. A comparison was made with water saturations using the Archie equation with parameters measured in the B-18 core. The Waxman-Smits model yielded significantly lower water saturations. Reservoir pressures were obtained from numerous wireline pressure measurements in the B-17 and B-18 wells.

Volumetric calculations were performed on the S reservoir to determine whether significant incremental natural gas remained to be developed. The S reservoir conditions were modeled to determine the time required for pressure communication between wells and, subsequently, to demonstrate the existence of a permeability barrier within the S_4 reservoir sandstone.

This report summarizes the results of the integrated geological, petrophysical, engineering, and seismic research as part of a broader project to investigate targeted technology applications for infield reserve growth in McAllen Ranch field. Reevaluation of the extent of the field reservoir boundaries has had a dramatic positive impact on reserve growth. Stratigraphic and structural reinterpretation of Vicksburg natural gas reservoirs can provide tens of billion cubic feet of natural gas reserve increases. Restriction of gas flow by reservoir heterogeneity results in opportunities for infill wells and recompletions. The South Texas Vicksburg deltaic reservoir gas play will undergo significant reserve growth as these opportunities are pursued.

Simulation system for compartmented gas reservoirs: targeted technology applications for infield reserve growth: by Collins, R. E., and Lord, M. E., 1992, Research & Engineering Consultants, Inc., topical report prepared for The University of Texas at Austin, Bureau of Economic Geology, the Gas Research Institute under contract no. 5088-212-1718, and the U.S. Department of Energy under contract no. DE-FG21-88MC25031, Report No. GRI-92/0104, 75 p.

This report summarizes the development of an engineering method for analysis of field production data in order to evaluate compartmented gas reservoirs that utilizes only pressure and production data commonly recorded and available in public domain sources.

The SGR study of sandstone reservoirs has concentrated in Seeligson, Stratton, and McAllen Ranch fields in the Frio-Vicksburg trend of South Texas. Reservoirs in Seeligson and Stratton fields are fluvial and fluvial-deltaic depositional systems. These reservoirs exhibit relatively high permeability, whereas the McAllen Ranch reservoirs are deep, overpressured, deltaic, Vicksburg reservoirs with low permeability. It was found that the model described in this report was not appropriate for the tight sandstones found in McAllen Ranch field. This was because in low-permeability reservoirs conventional shut-in pressures are not representative of the average compartment pressures predicted by the compartment model. In McAllen Ranch field it is also suspected that creep compaction is a significant drive mechanism and on the basis of production data alone it is impossible to distinguish between reservoir response due to compartmentalization and that due to creep compaction. However, the technique proved applicable to the higher permeability reservoirs of Seeligson and Stratton fields. The model was used to quantify reservoir production behavior due to compartmented reservoir structure. The effect of leakage across a low-permeability barrier from an unproduced compartment to a produced compartment is demonstrated. This effect is shown to introduce special characteristics in pressure and production rate histories. These effects can then be used as a screening tool to select wells indicating poorly drained compartments. Actual field production data are modeled (history-matched) to produce quantitative estimates for drained and partially drained reservoir volumes and the degree of communication between them. This information can be correlated with the geological description of the drained areas. It is shown that in some cases this information is supportive of the geological description, whereas in other cases the results suggest that an oversimplification of the geology of the area has been stated. For example, a channel sand structure that appears relatively uniform from the geological analysis of the area is shown from compartment modeling to exhibit a more complex or compartmented structure. This could be accounted for by point-bar deposition with internal barriers or baffles to flow.

The reservoir is conceptualized as being composed of one or more compartments, with flow between compartments through low-permeability barriers. A barrier between compartments can be varied from impermeable to highly permeable. Production is allowed from any compartment. Typically, certain compartments are produced while other compartments are unproduced except by flow through compartment boundaries. The computer model simulates the average pressure response of each compartment for any assigned rate or pressure drawdown histories assigned to all wells. Field data can be history-matched by adjusting model parameters, such as compartment pore volumes and barrier transmissibilities, until the model response is in agreement with the observed field data. The parameters from the model history-match then characterize the reservoir structure.

Development and implementation of the compartmented reservoir simulator has been a key result of the GRI/DOE/State of Texas Secondary Natural Gas Recovery project. This tool has given the project considerable insight into the behavior of heterogeneous reservoirs. In particular it has proved to be very useful in identifying areas of likely reserve growth opportunity. Because of its applicability as a reservoir analysis tool for screening reservoirs, efforts are underway to make this PC-based software commercially available to the gas-producing industry.

Secondary natural gas recovery: targeted technology applications for infield reserve growth in fluvial reservoirs in the Frio Formation, Seeligson field, South Texas: by Ambrose, W. A., Grigsby, J. D., Hardage, B. A., Langford, R. P., Jirik, L. A., Levey, R. A., Collins, R. E., Sippel, M. A., Howard, W. E., and Vidal, J. M., 1992, The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the Gas Research Institute under contract no. 5088-212-1718 and the U.S. Department of Energy under contract no. DE-FG21-88MC25031, Report No. GRI-92/0244, 200 p.

The objective of this report is to better enable natural gas producers to develop additional natural gas resources in fields with conventional porosity and permeability. Heterogeneities in fluvial reservoirs are described and evaluated in Seeligson field, a mature gas field located in the Oligocene middle Frio Formation in the Frio Fluvial/Deltaic Sandstone along the Vicksburg Fault Zone (FR-4) play in South Texas. This field study serves as a model in its approach to incremental resource development.

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 conventional porosity and permeability. These reservoirs may contain incompletely drained compartments that are defined primarily by depositional-facies heterogeneity and secondarily by structural heterogeneity and local variations in porosity and permeability. In many fields in the FR-4 play, complex fluvial reservoirs contain opportunities for identifying potentially undrained reservoir compartments.

Remaining natural gas in these compartments can be contacted either by recompletion of old wells that have bypassed these compartments or by infill wells that contact compartments not drained at current well spacing. Exploration for compartments or bypassed gas zones in old fields can be improved using detailed geologic studies that integrate engineering, petrophysical, and geophysical methods.

This report summarizes the results of the research program that evaluated the potential for secondary gas recovery in middle Frio fluvial reservoirs in Seeligson field. These reservoirs consist of channel-fill and crevasse-splay reservoir sandstones that are bounded by levee and floodplain nonreservoir siltstones and mudstones. The potential for secondary gas recovery in these reservoirs at Seeligson field is less than that of other middle Frio reservoirs in other fields in the FR-4 play. Seeligson field contains well-connected fluvial sandstones that have been effectively drained by relatively greater numbers of completions. In contrast, other fields in the play (Stratton and Agua Dulce) contain less intensively completed, isolated fluvial sandstones that represent uncontacted or incompletely drained reservoir compartments. Differences in fluvial reservoir architecture and completion practices must be considered as an important part of any infield exploration program for fields in the FR-4 play and in other gas plays.

In an early phase of the research that was conducted as part of a GRI coproduction study, bypassed gas zones were identified by geologic reservoir-characterization methods and advanced petrophysical techniques. The reserve-growth potential of bypassed and untapped zones was evaluated from cased-hole logs. Pulsed-neutron, gamma-ray, and acoustic logs were recorded in selected cased holes and interpreted with new techniques that identified gas-bearing zones. Five recompletions were made in two zones (14B and 19B) that together have produced more than 1.4 Bcf of additional gas in approximately 18 months from incompletely drained reservoir compartments. These compartments occur in structurally high sandstones that are also bounded by channel-on-channel contacts where partial permeability barriers are inferred to exist along mudstone-intraclast zones.

Other reservoirs (Zones 15 and 19C) also have a high degree of internal architectural complexity. However, these reservoirs also have a high completion density and therefore contain only a limited number of undrained reservoir compartments. Effective drainage in the Zone 15 reservoir has occurred (1) between small splay compartments that are well connected to channel-fill compartments and (2) along depositional axes of individual channel-fill complexes. Although few compartments occur between closely spaced wells (<3,000 ft [<915 m]) in the Zone 15 reservoir, even between wells in different facies (for example, proximal-splay and channel-fill), compartments may occur in channel-fill complexes that are distantly separated (≥5,000 ft [≥1,524 m]) from other channel-fill complexes by mudstone-rich floodplain and distal-splay deposits. These well-separated channel-fill complexes can be targeted for recompletions or infill wells because they have been incompletely drained by wells in other channel-fill complexes, even though the distant completions are at the same stratigraphic level.

The research integrated geologic mapping, petrophysical techniques, engineering analysis, and geophysical measurements to evaluate the impacts of reservoir heterogeneity on the recovery of incremental gas. Eight tasks were undertaken to meet the major project objectives. Parts of tasks (1) through (4) were undertaken in an early phase of the research that was conducted as part of a coproduction study, whereas tasks (5) through (8) were undertaken later as part of the Secondary Natural Gas Recovery project. These tasks were the following:

(1) To evaluate fields and reservoirs in the FR-4 play that have potential for containing bypassed gas-bearing zones and uncontacted compartments

(2) To select a field in the play for study and to develop a cooperative relationship with the field operator to facilitate data acquisition and to formulate recompletion strategies

(3) To provide a detailed geological characterization of selected gas reservoirs in the field and to describe depositional and diagenetic controls on reservoir geometry

(4) To identify potential reservoir compartments containing uncontacted or bypassed gas and to recommend these recompletion targets to the field operator for evaluation with cased-hole logging

(5) To use the results of cased-hole logging to evaluate reserve additions in bypassed zones in the field

(6) To select a site in the field to conduct an experiment from which reservoir heterogeneity could be inferred from pressure-communication tests

(7) To characterize and contrast different scales of reservoir heterogeneity in the field from seismic, geologic, engineering, and petrographic data

(8) To evaluate the gas-reserve growth potential of Seeligson field by comparing its fluvial sandstone architecture and reservoir completion density with that of other fields in the FR-4 play.

This report summarizes the results of integrated geological, petrophysical, engineering, and seismic research as part of a broader project to investigate technology applications for infield reserve growth in Seeligson field. Analysis of multiple gas reservoirs in stratigraphically complex Tertiary fluvial deposits in the Seeligson gas cap indicates that only a limited reserve growth potential exists in well-connected fluvial sandstones, both along individual channel axes and between closely spaced completions, even in different facies in the same genetic unit. In contrast, there are reserve growth opportunities in fluvial channel complexes that are distantly separated from adjacent channel systems by intervening deposits of floodplain mudstones that serve as lateral seals and baffles to gas flow at the same stratigraphic horizon.

Highly variable (1) stratigraphic overprint on reservoir architecture, (2) diagenetic effects on reservoir quality, and (3) operator completion strategies in the Frio Fluvial/Deltaic Sandstone along the Vicksburg Fault Zone gas play (FR-4) will require operators to assess these three main factors to evaluate the secondary resource potential of other fields in this play or in similar gas plays. Comparison of Seeligson field with other Frio fields in the FR-4 play (for example, Stratton and Agua Dulce) indicates that the secondary gas resource potential in these fields is greater than that in Seeligson field.

Secondary natural gas recovery: use of dipmeters in stratigraphic and depositional interpretation of natural gas reservoirs of the Oligocene Vicksburg Formation: an example from McAllen Ranch field, Hidalgo County, Texas, of targeted technology applications for infield reserve growth: by Langford, R. P., and Hall, J. D., 1992, The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the Gas Research Institute under contract no. 5088-212-1718 and the U.S. Department of Energy under contract no. DE-FG21-88MC25031, Report No. GRI-91/0261, 80 p.

The objective of this report is to improve the analysis and interpretation of dipmeters in growth-faulted environments, to identify methods for integration into mapping and seismic interpretation, to identify methods of using the dipmeter to interpret sedimentary features observed in cores and to compare hole breakouts to formation stress data, and to apply these techniques to the search for incremental reserves in mature natural gas fields.

Both DOE and GRI have been conducting research directed at identifying methods of detecting and tapping incremental natural gas in existing fields. The dipmeter provides measurements that can be extrapolated away from the well bore and that can aid in the integration of well data into fieldwide data such as well-to-well correlations and seismic data. The McAllen Ranch field provided a base of dipmeter data in a growth-fault-dominated mature Vicksburg gas field where new wells are being drilled.

Optimum application of the dipmeter involves data acquisition, processing, display, and interpretation. Processing parameters were optimized by comparing various computed results to the sedimentary features observed in cores. Critical structural and sedimentary anomalies can be identified on the dipmeter. Structural and sedimentary results from the dipmeter can then be extrapolated to other zones and wells that were not cored. The interpretation of these results can be integrated with mapping, production, and seismic data.

The dipmeter 4-arm calipers can be processed for hole breakout orientation and compared to formation stress data for planning hydraulic fracture treatments. Dipmeters and other logs from 15 wells from the Shell McAllen "B" lease in Hidalgo County, Texas, were entered into a data base maintained for GRI. All wells were processed for structural dip data, and five wells, including two with cores, were processed for stratigraphic dip data. Processing parameters were optimized to give the best results compared to cores. Expanded-scale microresistivity curves were compared to cores to determine the type and scale of features that could be identified. Processing parameters were adjusted to enhance the dipmeter results compared to the features.

Dipmeter results and other logs were plotted on various depth scales from 1:1 to 1:5,000 to provide correlations to data from the scale of cores to seismic. Schmidt plots were made of the various sandstones and apparent structural anomalies to detect any change in azimuth in the vertical section and between wells. Dip projections were made along VSP and seismic lines and between wells.

Calipers were processed to identify the degree and azimuth of hole elongation through the S zone. These results were compared to acoustic anisotropy data from cores.

Rotation of strata into a major growth fault west-northwest of the B area is the predominant influence on all dipmeters. The sediments affected by the growth fault can be divided into stratigraphically defined domains, rotated to approximately the same dips and azimuths. The variation in azimuths of rotation indicates that the area of maximum subsidence shifted along the fault. Because in a growth fault zone the area of maximum subsidence corresponds to the area of maximum deposition and thus to the thickest reservoir sandstones, the inferences drawn from the azimuths of rotation can be used to infer the direction of offset sandstone thickness. This technique successfully predicts the thickness patterns within the S_1 and S_2 sandstones of the Vicksburg S reservoir.

Wells with axes of rotation that vary from the rest may be inferred to be separated by active growth faults. This technique successfully predicted a growth fault that was subsequently imaged on three-dimensional seismic between the B-3 well and the rest of the B area wells.

Changes in the number and character of dip domains within the growth-fault-influenced section may be used to infer that intervals are not stratigraphically correlative. This technique allows correct interpretation of stratigraphic change rather than fault offset of the S reservoir along the western margin of the B area. A similar reinterpretation by Shell Western Exploration and Production, Inc., resulted in 100 Bcf of added reserves since 1987 (Hill and others, 1991).

Slumps provide a potential source of reservoir heterogeneity that must be considered in fields with similar depositional environments. Numerous slumps and small faults pervade the stratigraphic interval affected by the growth fault. These slumps are down toward the fault and are interpreted to reduce the permeability in the direction of the fault. A large slump was also evident on the VSP. Interpretation of these slumps aided in the geologic interpretation of the movement of the growth fault and associated deltaic sequences.

Hole breakout azimuths on five wells were compared to azimuths derived from acoustic anisotropy to define formation stress vectors. The two measurement techniques agreed within 23°. This is considered a good match because of the low precision of acoustical anisotropy results. This comparison indicates that hole eccentricity can be used to predict horizontal stress vectors. These results proved extremely useful in creating a reservoir model of part of the S reservoir in the B area that was used to quantify permeability barriers within the area and to identify areas with potential for unrecovered resources.

This report summarizes results of dipmeter analysis performed as part of the Secondary Gas Recovery Project within McAllen Ranch field, South Texas. The purpose of the study was to determine if features reflected on dipmeters could be useful in finding reserves of gas in similar fields. The correlation of dipmeter features with geologic interpretations that resulted in discovery of 100 Bcf of natural gas reserves indicates that similar combined geologic-petrophysical studies in other fields should result in significant reserve additions by operators. These results have been presented as part of the Secondary Gas Recovery short course. Operators have been approached for small-scale geologic analyses of Vicksburg reservoirs to demonstrate the utility of this and similar studies.

Targeted technology applications for infield reserve growth in deltaic sand-rich, low- to conventional-permeability reservoirs in the Wilcox Group, Lake Creek field, Texas: by Grigsby, J. D., Guevara, E., Levey, R. A., Sippel, M. A., Howard, W. E., and Vidal, J. M., 1992, The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the Gas Research Institute under contract no. 5088-212-1718 and the U.S. Department of Energy under contract no. DE-FG21-88MC25031, Report No. GRI-92/0471, 105 p.

The objective of this report is to better enable natural gas producers to develop additional natural gas resources in fields with low to conventional permeability and porosity. Heterogeneities in late Paleocene-age reservoirs are described and evaluated in Lake Creek field, a mature gas field located in the Wilcox Deltaic Sandstone in the Houston Embayment (WX-1) play in Texas. This field study serves as a model in its approach to incremental resource development for similar gas fields.

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 incompletely drained compartments that are defined primarily by a combination of depositional-facies and diagenetic heterogeneity and secondarily by structural heterogeneity. In many low- to conventional-permeability gas fields, complex deltaic reservoirs contain opportunities for identifying potentially undrained reservoir compartments. Remaining natural gas in these compartments can be contacted by the recompletion of existing wells that have bypassed these compartments or by the drilling of infield wells that contact compartments not effectively drained at current well spacing. Exploration for compartments or bypassed gas zones in old fields can be improved using detailed geologic studies that integrate engineering, petrophysical, and geophysical methods.

This report summarizes the results of research designed to evaluate the potential for secondary gas recovery in deltaic reservoirs in the lower Wilcox Group in Lake Creek field. These reservoirs consist of delta-front, channel-mouth-bar, and distributary-channel reservoir sandstones that are bounded by prodelta and delta-plain nonreservoir siltstones and mudstones. Analyses of secondary gas recovery potential in these reservoirs at Lake Creek indicate that a technically recoverable resource potentially exceeds the expected ultimate recovery from currently developed wells in the G reservoir. Some part of this resource will be recoverable through additional infield development of existing well bores and through new well bores.

No attempt has been made to estimate the number of wells that might be required to fully develop the incremental resources identified by this study. Reservoir heterogeneity has probably resulted in multiple independent or poorly connected reservoir compartments. The reserve growth potential estimated in this analysis assumes that enough wells will be drilled to penetrate and effectively drain all such compartments. Actual development strategy, however, will depend largely on economic factors, which are beyond the scope of this study.

Detailed stratigraphic analysis of the lower Wilcox indicates that the G sandstone in Lake Creek field is composed of at least four parasequences. An analog comparison of lower Wilcox deltaic reservoirs in the subsurface with laterally continuous outcrop exposures was analyzed as part of a concurrent GRI research effort in the Ferron Sandstone in Utah. Similar trends in permeability from nearly identical depositional facies, both in whole cores from the subsurface Wilcox deltas and in Ferron outcrops, were documented by extensive minipermeameter measurements.

A well-log-based model to predict free-water level and effective permeabilities was also successfully tested in these lower Wilcox gas reservoirs. This model relates the four important reservoir properties of porosity, water saturation, permeability, and capillary pressure with a single equation. Detailed petrographic analysis from whole cores obtained in a GRI cooperative well indicates that fibrous illites will cause artificially high permeability measurements when industry standard procedures using conventionally dried core plugs are used to assess permeability.

The research integrated geologic subsurface mapping, petrophysical techniques, and engineering analysis to evaluate the impacts of both depositional and diagenetic reservoir heterogeneities on the recovery of incremental gas. The technical approach included the following:

(1) Subsurface mapping of the G sandstone using well logs calibrated to core data to determine genetic depositional units, reservoir variability, and stacking patterns.

(2) Acquisition of high-resolution well-log data in GRI cooperative wells to determine applicability of state-of-the-art logging techniques in identifying infield gas resources.

(3) Application of a well-log-based permeability model that relates porosity, water saturation, permeability, and capillary pressure with a single equation.

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

(5) Comparison of the permeability structure in identical depositional facies identified in subsurface whole cores and in depositionally analogous outcrops.

This report summarizes the results of the integrated geological, petrophysical, and engineering research as part of a broader project to investigate technology applications for infield reserve growth in Lake Creek field. Analysis of gas reservoirs in stratigraphically complex Tertiary deltaic deposits in the Lake Creek gas field indicates that reserve-growth potential exists in sandstone-rich deltaic reservoirs.

Variability in the stratigraphic reservoir architecture and the diagenetic effects on reservoir quality in the Wilcox Deltaic Sandstone in the Houston Embayment (WX-1) gas play will require operators to assess these conditions to evaluate the secondary resource potential of other fields in this play or in similar gas plays.

Targeted technology applications for infield reserve growth: case studies for evaluating the benefits of secondary gas recovery, onshore Gulf Coast, South Texas: by Levey, R. A., Burn, M. J., Ambrose, W. A., Ruthven, C. L., Sippel, M. A., Vidal, J. M., Howard, W. E., and Ballard, J. R., 1993, The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the Gas Research Institute under contract no. 5088-212-1718 and the U.S. Department of Energy under contract no. DE-FG21-88MC25031, Report No. GRI-92/0225, 124 p.

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.

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.

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.

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.

The technical approach included

(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.

The cost-benefit analysis for each case study included

(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.

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.

Targeted technology applications for infield reserve growth in fluvial reservoirs, Stratton field, South Texas: by Levey, R. A., Hardage, B. A., Langford, R. P., Scott, A. R., Finley, R. J., Sippel, M. A., Collins, R. E., Vidal, J. M., Howard, W. E., Ballard, J. R., Grigsby, J. D., and Kerr, D., 1993, The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the Gas Research Institute under contract no. 5088-212-1718 and the U.S. Department of Energy under contract no. DE-FG21-88MC25031, Report No. GRI-93/0187, 244 p.

The primary objective of this report is to better enable natural gas producers to develop additional natural gas resources in fields with conventional permeability and porosity. Integrated geologic, geophysical, reservoir engineering, and petrophysical evaluations in mid-Oligocene-age fluvial reservoirs are evaluated from Stratton field, a mature gas field located in the Frio Fluvial/Deltaic Sandstone along the Vicksburg Fault

Zone (FR-4) play in South Texas. This multidisciplinary field study serves as a testing area and model in its approach to incremental resource development for other gas fields.

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 conventional porosity and permeability. Secondary or incremental gas may be contained in reservoirs that are untapped or bypassed or have incompletely drained compartments that primarily are a function of depositional facies and diagenetic heterogeneity and secondarily are dependent upon structural heterogeneity. Multiple stacked reservoirs deposited in thick stratigraphic intervals such as the FR-4 play and other fluvially dominated units can be affected by variations in sandstone stacking patterns and contain opportunities for identifying reserve appreciation in existing fields. Remaining natural gas in these fields can be contacted either by recompletion of existing wells that have bypassed these reservoir compartments or by infield wells that contact compartments not effectively drained at the current well spacing. Exploration for new reservoirs, incompletely drained compartments, or bypassed gas zones in old fields can be improved using detailed geologic studies that integrate engineering, petrophysical, and geophysical methods.

This report summarizes the results of research designed to evaluate the effectiveness of extensive infield development accomplished by drilling new wells or by recompleting previous wells for secondary gas recovery in fluvial reservoirs in the middle Frio Formation of Stratton field. These reservoirs consist of channel-fill and splay deposits that are bounded by nonreservoir floodplain, levee, and abandoned channel-fill siltstones and mudstones.

Significant natural gas reserve appreciation opportunities exist in heterogeneous fluvial reservoirs that are prone to multiple compartments. Reserve appreciation of 100 percent is documented for a large contiguous area in Stratton field after 40 years of prior development.

Project analysis indicates that an additional technically recoverable gas resource of 48 Bcf is present in the Wardner lease study area. However, part of that gas resource is found in the middle Frio interval, where reservoir permeability is often affected by diagenetic alteration and may need hydraulic stimulation.

Using the Gas-Wizard compartmented reservoir simulator, 3 classes of compartment sizes were delineated from 10 groups of Frio reservoirs. Forward stochastic modeling of maximum gas recovery indicates that well spacings of 340, 200, and 60 acres (or less) provide the maximum gas-contact efficiency in large, medium, and small compartment-size reservoirs, respectively.

Currently available geophysical techniques, including three-dimensional surface seismic, vertical seismic profiling, amplitude-versus-offset, and two-dimensional seismic inversion, were used to image subtle changes in reservoir topology and compartment boundaries at depths as low as 6,800 ft.

The research integrated geologic subsurface mapping, engineering analysis of project-designed well tests, open- and cased-hole petrophysical techniques, and both surface and downhole geophysical methods to evaluate the impact of both depositional and diagenetic reservoir heterogeneities on the recovery of incremental gas. The technical approach included

(1) Subsurface mapping of lithostratigraphic units corresponding to operator-designated regulatory gas reservoirs in the middle Frio stratigraphic interval

(2) Calibration of core and rock properties to well logs to determine genetic depositional units, reservoir variability, and stacking patterns

(3) Determining the statistics of primary pore volume and transmissibility for each of 10 reservoir groups and then defining 3 classes of reservoir compartment sizes (large, medium, and small) delineated from a spectrum of fluvial reservoirs

(4) Forward stochastic modeling of abundant Stratton field data to analyze gas recovery versus well spacing for infill development of different types of meandering fluvial systems

(5) Acquisition and interpretation of three-dimensional surface seismic and high-resolution vertical seismic profiles to image seismic thin beds corresponding to high-reserve-growth gas reservoirs.

This report summarizes the results of the integrated geological, geophysical, petrophysical, and engineering research as part of a broader project to investigate technology applications for infield reserve growth in fluvial-deltaic reservoirs. Analysis of gas reservoirs in stratigraphically complex Tertiary fluvial deposits in Stratton field indicates that significant reserve appreciation potential exists in heterogeneous and compartmentalized fluvial reservoirs. Continued operator access to reserve appreciation in the FR-4 play and in other similar gas plays in the lower 48 states will require application of SGR technologies and concepts.

ANNOTATED LIST OF PROJECT TECHNICAL PUBLICATIONS (Listed Alphabetically by Author)

Secondary natural gas recovery in mature fluvial sandstone reservoirs, Frio Formation, Agua Dulce field, South Texas: by Ambrose, W. A., Levey, R. A., Vidal, J. M., Sippel, M. A., Ballard, J. R., Coover, D. M., Jr., and Bloxsom, W. E., 1993, Gulf Coast Association of Geological Societies Transactions, v. 43, p. 11–24.

An approach that integrates detailed geologic, engineering, and petrophysical analyses, combined with improved well-log analytical techniques, can be used by independent oil and gas companies for successful infield exploration in mature fields in the Gulf Coast that larger companies may consider uneconomic. A potential incremental natural gas resource of 9.6 Bcf, of which 3.1 Bcf may be economically recoverable, was identified in a 490-acre lease in Agua Dulce field. Uncontacted gas resources at Agua Dulce field occur in thin (typically less than 10-ft [<3-m]) bypassed zones that can be identified through a computed log evaluation that integrates open-hole logs, wireline pressure tests, fluid samples, and cores.

The identification and evaluation of bypassed and incompletely drained gas reservoirs in the wave-dominated deltaic system of the Frio Formation (Oligocene), North McFaddin field, Victoria County, South Texas: by Burn, M. J., Sippel, M. A., Vidal, J., Ballard, J. R., Levey, R. A., and Knowles, P., 1993, Gulf Coast Association of Geological Societies Transactions, v. 43, p. 47–56.

An integrated geologic, engineering and petrophysical evaluation of North McFaddin field targeted actual and potential secondary natural gas resources within thin reservoirs. Contour maps of net sandstone thickness, relative spontaneous potential deflection, and resistivity were superposed for each reservoir unit. These data were integrated with structure maps, well-test production, wireline formation tests, and sidewall core data, which allowed the potentially productive limits of each reservoir unit to be delineated. These procedures enabled not only the recommendation of recompletion targets but also the strategic placement of a potential development well location.

Applications of transient pressure interference tests to fractured and nonfractured injection wells: by Cooper, K. J., and Collins, R. E., 1989, Society of Petroleum Engineers, paper no. SPE 19785, p. 153–163.

Transient pressure interference tests have proved to be very effective for determining parameters for reservoir simulation of deep-well, hazardous waste, injection systems. A number of multiwell systems are described in a variety of geological settings to demonstrate the wide range of systems in which interference testing has been utilized with remarkable success.

Evidence and strategies for infield reserve growth of natural gas reservoirs: by Finley, R. J., Levey, R. A., Hardage, B. A., and Sippel, M. A., 1992, *in* Thompson, H. A., ed., Preprints of the 1992 International Gas Research Conference: Gas Research Institute, American Gas Association, U.S. Department of Energy, p. 13–22.

Results of this joint venture research project indicate that compartments exist in natural gas reservoirs. The critical factor for operators is the recognition of reservoir compartments, their sizes, and the degree of barrier transmissibility between compartments. Detailed geologic facies mapping, high-resolution vertical seismic profiling, three-dimensional surface seismic surveying, and use of a newly developed multicompartment reservoir production and pressure history simulator all contribute to the assessment of reserve growth within conventional permeability gas reservoirs.

Diagenetic variability in middle Frio Formation gas reservoirs (Oligocene), Seeligson and Stratton fields, South Texas: by Grigsby, J. D., and Kerr, D. R., 1991, Gulf Coast Association of Geological Societies Transactions, v. 41, p. 308–319.

Two distinct reservoir types (type I and type II), differentiated on the basis of framework mineralogy, diagenetic history, and reservoir quality, are present in the

Oligocene middle Frio Formation in Seeligson and Stratton fields, South Texas. Type I reservoirs are characterized by well-developed intergranular porosity and a corresponding strong correlation between porosity and permeability. Type II reservoirs are characterized by poorly developed intergranular porosity and a corresponding poor correlation between porosity and permeability. Recognition and description of these two types of reservoirs in the middle Frio Formation and an understanding of the differences will aid in improving production practices in the future.

Effects of fibrous illite on permeability measurements from preserved cores obtained in lower Wilcox Group gas sandstones, Lake Creek field, Montgomery County, Texas: by Grigsby, J. D., Vidal, J. M., Luffel, D. L., Hawkins, J., and Mendenhall, J. M., 1992, Gulf Coast Association of Geological Societies Transactions, v. 42, p. 161–172.

The strategic location of fibrous illite in the pore network reduces reservoir permeability in lower Wilcox Group gas sandstones in Lake Creek field. Although quartz cement is the dominant authigenic mineral in these sandstones, it is the fibrous illite, which ranges from 3 to 8 percent of the whole rock volume and extends into and bridges the main permeability pathways, that largely influences reservoir quality.

Detecting compartmentalization in gas reservoirs through production performance: by Hower, T. L., and Collins, R. E., 1989, Society of Petroleum Engineers, paper no. SPE 19790, p. 213–225.

Diagnostic techniques are presented for detecting and quantifying poorly drained compartments in volumetric gas reservoirs. It is shown that p/z versus G_p data can be used to assess unrecovered gas reserves and assist in targeting infield development.

Reservoir heterogeneity in middle Frio fluvial sandstones: case studies in Seeligson field, Jim Wells County, Texas: by Jirik, L. A., 1990, Gulf Coast Association of Geological Societies Transactions, v. 40, p. 335–351.

Detailed evaluation of middle Frio (Oligocene) fluvial sandstones reveals a complex architectural style potentially suited to the addition of gas reserves through identification of poorly drained reservoir compartments and bypassed gas zones. Reservoir zones 15 and 19C were studied in an 11-mi^2 (28-km^2) area in Seeligson field. Although these reservoirs are currently considered low-pressure producers nearing depletion, recent well completions and bottom-hole pressure data indicate that untapped or poorly drained compartments are being encountered.

Identification of bypassed gas reserves through integrated geological and petrophysical techniques: a case study in Seeligson field, Jim Wells County, South Texas: by Jirik, L. A., Howard, W. E., and Sadler, D. L., 1991, Society of Petroleum Engineers, paper no. SPE 21483, p. 7–16.

Bypassed gas zones can be identified and developed by integrating advanced geologic methods and petrophysical techniques into field development strategies. Detailed geologic evaluation of middle Frio reservoirs in Seeligson field reveals a stratigraphic framework composed of multiple stacked fluvial channel-fill and splay deposits interstratified with floodplain mudstones. In Seeligson field, reservoirs were studied for bypassed gas potential and evidence of incomplete drainage due to compartmentalization. Middle Frio sandstones were described and mapped, identifying reservoir-quality facies. Pulsed-neutron, gamma-ray, and acoustic logs were recorded in selected cased holes and interpreted using new techniques that demonstrate their effectiveness in identifying gas-bearing zones. Five successful recompletions were made in two zones that have produced more than 1.4 Bcf of gas in approximately 18 months.

Well performance evidence for compartmented geometry of oil and gas reservoirs: by Junkin, J. E., Sippel, M. A., Lord, M. E., and Collins, R. E., 1992, Society of Petroleum Engineers, paper no. SPE 24356.

Well pressure and production histories and transient pressure tests, evaluated by conventional well testing techniques and simulation, are shown to indicate compartmented reservoir geometry arising by depositional and diagenetic processes. Examples are cited of both clastic and carbonate reservoirs, but the central focus of this study is on fluvial deposits exhibiting stratigraphic compartmentalization.

Reservoir heterogeneity in the middle Frio Formation: case studies in Stratton and Agua Dulce fields, Nueces County, Texas: by Kerr, D. R., 1990, Gulf Coast Association of Geological Societies Transactions, v. 40, p. 363–372.

The middle Frio is composed of sand-rich channel-fill and splay deposits interstratified with floodplain mudstones, all forming part of the Gueydan fluvial system. Channel-fill deposits are 30 ft (9 m) thick and 2,500 ft (763 m) wide. Splay deposits are as much as 20 ft (6 m) thick proximal to channels and extend as much as 2 mi (3 km) from channels. Channel-fill and associated splay sandstones are reservoir facies (porosity = 20 percent; permeability = tens to hundreds of millidarcys); floodplain mudstones and levee sandy mudstones impede or obstruct flow and separate individual reservoirs and compartments both vertically and laterally.

Fluvial architecture and reservoir compartmentalization in the Oligocene middle Frio Formation, South Texas: by Kerr, D. R., and Jirik, L. A., 1990, Gulf Coast Association of Geological Societies Transactions, v. 40, p. 373–380.

This paper provides an overview of the fluvial sedimentology and architecture of the middle Frio Formation in South Texas and assesses the potential role fluvial architecture plays in the compartmentalization of gas reservoirs. Relatively slow aggradation resulted in laterally stacked channel systems, which may lead to reservoirs with leaky barriers. By contrast, more rapid aggradation resulted in vertically stacked channel systems, which lead to more isolated reservoirs.

Recognition and implications of volcanic glass detritus in the fluvial deposits of the middle Frio Formation, South Texas: by Kerr, D. R., and Grigsby, J. D., 1991, Gulf Coast Association of Geological Societies Transactions, v. 41, p. 353–358.

Detrital volcanic glass has been identified in fluvial deposits of the middle Frio Formation of South Texas. Petrographic analysis of core samples from Seeligson and Stratton fields reveals abundant unabraded to slightly abraded, very fine sand- to silt-sized glass shards. Gamma-ray log response correlates with the presence of volcanic glass. Volcanic glass and API unit counts markedly increase through the medial third of the middle Frio and diminish toward the upper third of the middle Frio.

Minipermeameter study of fluvial deposits of the Frio Formation (Oligocene), South Texas: implications for gas reservoir compartments: by Kerr, D. R., Scott, A. R., Grigsby, J. D., and Levey, R. A., 1991, *in* Proceedings, Third International Reservoir Characterization Technical Conference III, Tulsa: National Institute for Petroleum and Energy Research and U.S. Department of Energy, p. 911–922.

More than 1,000 permeability measurements were made on three core segments using a minipermeameter (mechanical field permeameter). A very good correlation exists between the average permeability determined from minipermeameter measurements and the permeability relative to air determined by conventional methods, suggesting that the minipermeameter can be used reliably to evaluate permeability trends.

Gas well test analysis in complex heterogeneous reservoirs: by Kocberber, S., and Collins, R. E., 1991, Society of Petroleum Engineers, paper no. SPE 21512, p. 317–323.

Finite-element simulation must be the method of choice for evaluation of gas wells in complex, heterogeneous reservoirs. Simulation could be used for history-matching transient pressure tests with precision comparable to that of analytical solutions.

Sedimentary facies and petrophysical characteristics of cores from the lower Vicksburg gas reservoirs, McAllen Ranch field, Hidalgo County, Texas: by Langford, R. P., Grigsby, J. D., Howard, W. E., Hall, J. D., and Maguregui, J., 1990, Gulf Coast Association of Geological Societies Transactions, v. 40, p. 439–450.

This paper summarizes depositional and diagenetic features within selected reservoir intervals from McAllen Ranch field in northern Hidalgo County and illustrates how these features relate to reservoir quality in four cores obtained from the Shell A. A. McAllen B-18 well. Differences in the character of the microresistivity curve of the high-resolution dipmeter log correlate with differences in cementation and with different depositional facies within the cores. Comparison of microresistivity logs and cores allows extrapolation of facies and cement characteristics and resulting reservoir properties to uncored intervals.

Diagenesis and cement fabric of gas reservoirs in the Oligocene Vicksburg Formation, McAllen Ranch field, Hidalgo County, Texas: by Langford, R. P., and Lynch, F. L., 1990, Gulf Coast Association of Geological Societies Transactions, v. 40, p. 451–458.

McAllen Ranch field produces natural gas from 12 deep, overpressured sandstone reservoirs, each interpreted to be the deposit of a prograding shelf-edge delta. Correlation of petrographic and sedimentologic features reveals a predictable pattern of sandstone cementation. A predictable relationship between depositional facies and diagenetic facies allows extrapolation of the distribution of cements and the resultant reservoir characteristics to uncored wells and intervals with the objective of maximizing recovery of natural gas.

Use of the enhanced density and microresistivity logs in interpreting diagenetic facies in Tertiary Gulf Coast sandstones: by Langford, R. P., Grigsby, J. D., and Howard, W. E., 1992, Transactions of the Society of Professional Well Log Analysts: Society of Professional Well Log Analysts, SPWLA 33rd Annual Logging Symposium, Paper BB, 16 p.

Two high-resolution well logs may be used with core to improve estimates of porosity and permeability. The microresistivity log from the high-resolution dipmeter and the enhanced-resolution bulk density log can differentiate portions of core cemented with different minerals in gas reservoir sandstones from the Oligocene Vicksburg Formation. Flagging the different diagenetic facies and making separate permeability-porosity regressions for chlorite- and calcite/quartz-overgrowth-cemented intervals allow a more consistent and accurate estimate of permeability than using a simple regression of all log and core data.

Incremental gas reservoir development in fluvial-deltaic plays of the Gulf Coast: by Levey, R. A., Langford, R. P., Hardage, B. A., Grigsby, J. D., Ambrose, W. A., Finley, R. J., and Guevara, E. H., 1992, Houston Geological Society, v. 34, no. 8, p. 30–31 and p. 42–44.

Results from well tests, logging, and geologic analysis indicate that stratigraphic and diagenetic compartmentalization contribute to effective segregation of flow units within nonassociated natural gas reservoirs. Resource estimates within the most heterogeneous fluvial-dominated reservoir intervals indicate that a resource target of as much as 50 percent more gas than conventional estimated ultimate recovery may benefit from targeted recompletions and strategically sited infield wells.

Stratigraphic compartmentalization within gas reservoirs: examples from fluvial-deltaic reservoirs of the Texas Gulf Coast: by Levey, R. A., Sippel, M. A., Finley, R. J., and Langford, R. P., 1992, Gulf Coast Association of Geological Societies Transactions, v. 42, p. 227–235; *also* 1992, South Texas Geological Society Bulletin, v. 33, no. 2, p. 7–16.

Stratigraphic compartmentalization results in effective segregation of flow units and incomplete recovery due to depositional and diagenetic heterogeneities within nonassociated natural gas reservoirs. Three examples of reservoirs that contain secondary gas resources in Stratton field are used to illustrate the type of incremental resources that may be common in fluvial reservoirs in mature gas fields. The incremental resource within each of the reservoirs studied ranges from approximately 1 to 2.6 Bcf per example.

Natural gas reserve replacement through infield reserve growth: an example from Stratton field, onshore Texas Gulf Coast Basin: by Levey, R. A., Sippel, M. A., Langford, R. P., and Finley, R. J., 1991, *in* Burchfield, T. E., and Wesson, T. C., chairpersons, Proceedings, Third International Reservoir Characterization Technical Conference: IIT Research Institute, National Institute for Petroleum and Energy Research, and U.S. Department of Energy, p. 943–954.

Analysis of publicly available production data for a 50-year-old gas field indicates that reserves may be effectively replaced with additional infield wells and recompletions within a mature gas field containing reservoirs that have conventional porosity (>15 percent) and permeability (>10 md). Reserve additions are derived from three sources: (1) new reservoirs that are deeper pool than the current production, (2) reservoirs already contacted in wellbores but not effectively drained by the current completion spacing, and (3) reservoirs that were previously bypassed or new reservoirs encountered by infield drilling as untapped reservoir compartments.

A compartmented simulation system for gas reservoir evaluation with application to fluvial deposits in the Frio Formation, South Texas: by Lord, M. E., Collins, R. E., Kocberber, S., and Kerr, D. R., 1990, Society of Petroleum Engineers, paper no. SPE 24308, p. 1–9.

The study presented here was designed to demonstrate that the compartment model is capable of describing drained pore volumes in diverse reservoir configurations. The simulation studies in this paper were designed to represent geological configurations typical of the fluvial reservoirs found in the middle Frio Formation of the Texas Gulf Coast.

Effects of crossbedding on well performance: by Lord, M. E., and Collins, R. E., 1989, Society of Petroleum Engineers, paper no. SPE 19587, p. 165–179.

The effects of crossbedding on transient pressure well tests have been investigated using a combination of numerical and analytical mathematical methods. It has been shown that for systems in which crossbed laminae are thin and closely spaced, relative to formation thickness, wells exhibit a negative skin factor and an effective permeability that are dependent on the dip angle of the crossbed laminae.

Detecting compartmented gas reservoirs through production performance: by Lord, M. E., and Collins, R. E., 1991, Society of Petroleum Engineers, paper no. SPE 22941, p. 575–581.

A technique for using production data to detect and quantify poorly drained compartments in gas reservoirs is described. The method is based upon a multicompartment tanklike model with well performance specified by an in-flow relationship. The technique is validated against a detailed finite-element simulation. Field examples are presented illustrating the utility of the technique in improving reservoir development strategies.

Gas study increases estimates: higher recovery rates possible in many fields: by Shirley, Kathy, 1992, American Association of Petroleum Geologists Explorer, v. 13, no. 12, variously paginated.

The first, 4-year phase of the SGR project study has been completed, confirming that much natural gas is being overlooked and left in the ground—especially in mature, producing areas. The project's primary goal is to assess opportunities for maximizing economic recovery of natural gas from mature fields and then develop and test state-of-the-art technologies and techniques with the short-term potential of enabling producers to better identify and produce unrecovered natural gas resources in known fields.

Gas reserve growth analysis of fluvial-deltaic reservoirs in the Frio and Vicksburg Formations located in the Stratton field, onshore Texas Gulf Coast Basin: by Sippel, M. A., and Levey, R. A., 1991, Society of Petroleum Engineers, paper no. SPE 22919, p. 337–344.

Stratton field is presented as an example of the significant additional gas reserves that are available through conventional drilling and completion methods using existing technology. The analysis of historical reserve growth of natural gas in this field provides insight into the advanced stages of a mature producing province that is representative of other mature producing provinces of the United States.

Shale porosity—its impact on well log modeling and interpretation: by Truman, R. B., Howard, W. E., and Luffel, D. L., 1989, Society of Professional Well Log Analysts, Inc., Thirteenth Annual Logging Symposium, June 1989.

Shale contains porosity that must be accounted for when evaluating well logs in shaly sands. Data are presented showing that in addition to relatively large amounts of total porosity (19–20 percent), shales may also contain significant effective porosity (8–12 percent). An example is shown for core analysis data obtained from both sand and shale in a Frio Formation gas reservoir in South Texas. A method of log analysis is then shown for modeling the total and effective porosity, as obtained from core analysis. The data presented in this paper show that effective porosity can exist in shales and store hydrocarbon. Although effective porosity may be difficult to determine from core analysis, every attempt should be made to determine its magnitude and impact on reservoir volumetrics.

Formation evaluation techniques for identifying secondary gas resources: examples from the middle Frio, onshore Texas Gulf Coast Basin: by Vidal, J. M., Howard, W. E., and Levey, R. A., 1991, *in* Burchfield, T. E., and Wesson, T. C., chairpersons, Proceedings, Third International Reservoir Characterization Technical Conference: IIT Research Institute, National Institute for Petroleum and Energy Research, and U.S. Department of Energy, p. 961–972.

Integrated analysis of open- and cased-hole well logs, cores, and wireline pressure tests, combined with production test results, were used to evaluate Frio fluvial-deltaic sandstones along the Vicksburg fault zone. Formation evaluation parameters, including shale volume porosity, formation water saturation, and permeability, were computed for logs from different service companies, after standardization and environmental corrections were applied. Core permeability measurements revealed both high- (>200 md) and low-permeability (<15 md) sandstone reservoirs. Identification of depleted zones was accomplished with wireline pressure tests and short-term production tests.

PROJECT ABSTRACTS (Listed Alphabetically by Author)

Collins, R. E., 1993, Stochastic modeling for risk analysis in infield development of natural gas reservoirs (abs.): Society of Petroleum Engineers, 68th annual technical conference and exhibition.

Finley, R. J., 1992, Integrated geological and geophysical characterization of Gulf Coast reservoirs for incremental natural gas recovery (abs.): Houston Geological Society/Houston Geophysical Society joint meeting.

Grigsby, J. D., Tyler, Noel, Guevara, E. H., and Kuich, Nanette, 1992, Application of outcrop information in the optimization of subsurface reservoir characterization for reserve growth (abs.), *in* Oltz, D. F., ed., Advances in reservoir characterization for improved oil recovery: unlocking the reservoir: Illinois Geological Society Symposium, p. 5–8.

Guevara, E. H., Grigsby, J. D., Tyler, Noel, and Kuich, Nanette, 1992, Outcrop-constrained characterization of stratigraphic architecture in deltaic gas reservoirs, Lake Creek unit, Texas (abs.): Gulf Coast Association of Geological Societies Transactions, v. 42, p. 807.

Jirik, L. A., Kerr, D. R., Zinke, S. G., and Finley, R. J., 1990, Fluvial architecture and reservoir heterogeneity of middle Frio sandstones, Seeligson field, Jim Wells and Kleberg Counties, South Texas (abs.): American Association of Petroleum Geologists Bulletin, v. 74, no. 5, p. 686.

Langford, R. P., 1991, Depositional and diagenetic fabric of gas reservoirs in the Oligocene Vicksburg Formation, McAllen Ranch field, Hidalgo County, Texas (abs.): Houston Geological Society Bulletin, v. 33, no. 8, p. 8.

Langford, R. P., 1991, Sequence stratigraphy of a lowstand wedge along an unstable continental margin, Oligocene Vicksburg Formation, South Texas (abs.): Geological Society of America, Abstracts with Programs, v. 23, no. 5, p. A242.

Langford, R. P., 1992, Deltaic depositional systems on an unstable shelf margin, Vicksburg Formation, South Texas (abs.), *in* American Association of Petroleum Geologists 1992 annual convention official program, p. 72.

Langford, R. P., Wermund, E. G., Zinke, S. G., Guevara, E. H., Finley, R. J., and Brewton, J. G., 1990, Facies architecture and reservoir compartmentalization in the McAllen Ranch gas field, Hidalgo County, Texas (abs.): American Association of Petroleum Geologists Bulletin, v. 74, no. 5, p. 700.

Levey, R. A., Hardage, B. A., Sippel, M. A., and Finley, R. J., 1993, Clues, techniques, and strategies for maximizing infield reserve growth of natural gas reservoirs (abs.): Society of Independent Professional Earth Scientists, 30th annual convention, San Antonio, Texas, p. 13–14.

Levey, R. A., Ray, R. R., Single, R. S., and Finley, R. J., 1991, Approaches to finding new gas in mature fields: an example from the middle Frio, onshore Texas Gulf Coast Basin (abs.): Gulf Coast Association of Geological Societies Transactions, v. 61, p. 407.

Levey, R. A., Sippel, M. A., Finley, R. J., and Langford, R. P., 1992, Stratigraphic compartmentalization within gas reservoirs: examples from fluvial-deltaic reservoirs of the Texas Gulf Coast (abs.): American Association of Petroleum Geologists Bulletin, v. 76, no. 9, p. 1461–1462.

Levey, R. A., and Xue, Liangqing, 1993, Distribution of the largest gas reservoirs in third-order depositional sequences and systems tracts of the Frio stratigraphic unit in the Gulf Coast basin (abs.): American Association of Petroleum Geologists annual convention.

Levey, R. A., Xue, Liangqing, and Sattar, Asad, 1993, Forward modeling of reservoir architecture and seismic response in third- and fourth-order depositional sequences: examples from the Paleogene in the Gulf Coast basin (abs.): American Association of Petroleum Geologists annual convention.

Solano, M., Chaney, P., and Levey, R. A., 1992, Integración de métodos y disciplinas para la detección y explotación de reservas adicionales en campos maduros [Integration of methods and disciplines for the detection and recovery of additional reserves in mature fields] (abs.): Simposium de Geofisica A. M. G. E.

Zinke, S. G., Jirik, L. A., Langford, R. P., and Finley, R. J., 1990, Vertical seismic profile applications for definition of reservoir heterogeneity—South Texas, Vicksburg and Frio sandstones: a secondary gas recovery project (abs.), *in* Sneider, Robert, Massell, Wulf, Mathis, Rob, Loren, Dennis, and Wichmann, Paul, eds., The integration of geology, geophysics, petrophysics, and petroleum engineering in reservoir delineation, description and management: American Association of Petroleum Geologists, Society of Exploration Geophysicists, Society of Petroleum Engineers, and Society of Professional Well Log Analysts, The Archie Conference Abstracts and Program, unpaginated.

PROJECT LECTURES AND PUBLIC ADDRESSES

Robert J. Finley

"Natural gas reservoir characterization: the Gas Initiative and Secondary Gas Recovery Projects."

"An assessment of the natural gas resource base of the U.S.": industry briefing with Office of Policy, Planning, and Analysis, U.S. Department of Energy, Denver, Colorado, and Houston, Texas, 1988.

"An assessment of U.S. natural gas resources": presented as part of a panel on Government View of Gas Supply at the American Gas Association, Washington Representatives Third Annual Issues Conference, Point Clear, Alabama, 1988.

"Gas availability—long range": presented to Gulf Coast Cogeneration Association, fall regional conference, Austin, Texas, 1988.

"Gas reserves growth: an overlooked bonanza?": presented to the Electric Power Research Institute, Annual Fuel Supply Seminar, Kansas City, Missouri, 1988.

"Importance of extended reserve growth in gas resource estimates": presented to the Potential Gas Committee, annual meeting, Phoenix, Arizona, 1988.

"Natural gas: a substantial resource at moderate prices": presented to The Western States Land Commissioners Association, San Diego, California, 1989.

"Reevaluating the U.S. natural gas resource base: reserves, resources, and reserve growth": presented to the Dallas Energy Council, Annual Energy Education Day, Dallas, Texas, 1989.

"Reserve growth in gas reservoirs: more gas from existing fields with an example from the Frio Formation, South Texas": presented to the Corpus Christi Geological Society, Corpus Christi, Texas, 1989.

"Secondary natural gas recovery: targeted technology applications for infield reserve growth, a status report": presented to the U.S. Department of Energy, Natural Gas Research and

Development Contractors Review Meeting, Morgantown, West Virginia, and to the Gas Research Institute, Natural Gas Supply Project Advisors Meeting, Chicago, Illinois, 1989.

"Natural gas: reserves, supply, and demand: an assessment of the natural gas resource base of the United States": presented to the Clean Air Texas/Texas Environmental Coalition, Cleaner Air for Texas Using an Alternative Fuel: Natural Gas Conference, Dallas, Texas, 1989.

"Natural gas: a national supply overview": presented to the University of Southern California, Jesse M. Unruh Institute of Politics Symposium (Natural Gas: Meeting California's Energy Needs and Air Quality Goals), Los Angeles, California, 1989.

"Gas reserve growth: a new source of natural gas supply": presented to the North American Natural Gas Supply and Markets Conference, Denver, Colorado, 1989.

"Gas reserve growth: a new source of natural gas supply": presented at the Second Annual North American Natural Gas Supply and Markets Industry Conference, Denver, Colorado, 1990.

"Natural gas supplies: present and future": presented at An Overview of the Texas CNG Industry Conference, Austin, Texas, 1990.

"Natural gas supply and gas reserve growth in the U.S. and Texas": presented to the Joint Meeting of Natural Gas Producers Association, West Texas Producers Forum, and Producers Forum, Midland, Texas, 1990.

"Natural gas resource availability": presented to the El Paso Natural Gas Company, Customer Meeting, Carefree, Arizona, 1990.

"Reevaluating the U.S. Natural gas resource base: reserves, resources, and reserve growth": presented to the South Texas Geological Society, San Antonio, Texas, 1990.

"Compartmentalized reservoirs": presented to Oryx Energy Company, 1991 Technology Futures Symposium, Dallas, Texas, 1991.

"Characterization of heterogeneous natural gas reservoirs: applications for incremental recovery in the Texas Gulf Coast": presented to A Forum on Improved Oil and Gas Recovery, Houston, Texas, 1991.

"Infield natural gas reserve growth/secondary gas recovery joint venture": presented to the Gas Research Institute, Natural Gas Supply Project Advisors Enhanced Production from Conventional Resources Meeting, Houston, Texas, 1991.

"Natural gas reserve replacement via infield reserve growth: an example from Stratton field, onshore Texas Gulf Coast Basin": presented to the Third International Reservoir Characterization Technical Conference, IIT Research Institute, National Institute for Petroleum and Energy Research, and U.S. Department of Energy, Tulsa, Oklahoma, 1992.

"Geological examples of current improved recovery technologies": presented to the Texas Independent Producers and Royalty Owners Association Forum on Improved Oil and Gas Recovery, Houston, Texas, 1992.

"Integrated geological and geophysical characterization of Gulf Coast reservoirs for incremental natural gas recovery": presented to the Joint Meeting of the Geophysical Society of Houston and the Houston Geological Society, Houston, Texas, 1992.

"Briefing on current and prospective natural gas recovery technologies": presented to Congressional staff members attending Natural Gas Fact-Finding Meeting, Enserch Corporation, Dallas, Texas, 1992.

"Incremental natural gas resources through infield reserve growth/secondary natural gas recovery": presented to the Natural Gas Research and Development Contractors Review Meeting, U.S. Department of Energy, Morgantown, West Virginia, 1992.

"Extrapolation of gas reserve growth potential: development of examples from macro approaches": presented to the 1992 Project Advisor Group Meeting, Gas Research Institute, Golden, Colorado, 1992.

"Infield natural gas reserve growth joint venture (secondary gas recovery)": presented to the 1992 Project Advisor Group Meeting, Gas Research Institute, Golden, Colorado, 1992.

"Integrated geological, petrophysical, geophysical, and engineering approach to evaluating the potential for infield natural gas reserve growth: examples from South Texas": presented to the Houston Geological Society, Houston, Texas, 1992.

"Improved oil and gas recovery: a symposium preview": presented to the 1992 Annual Meeting of the Texas Independent Producers and Royalty Owners Association, Fort Worth, Texas, 1992.

"A positive assessment of U.S. natural gas supply": presented to The University of Texas at Austin, Bureau of Business Research conference on the role of natural gas in environmental policy, Austin, Texas, 1992.

"Infield natural gas development: prospects for applications of new concepts": presented to the Electric Power Research Institute Workshop: Natural Gas Wellhead Deliverability Over the Intermediate Term, Houston, Texas, 1993.

Jeffry D. Grigsby

"Diagenesis of the lower Vicksburg Formation, McAllen Ranch field, Hidalgo County, Texas": presented at a BEG seminar, 1990.

"Impact of volcanic glass detritus on diagenesis in middle Frio Formation gas reservoirs, Stratton and Seeligson fields, South Texas": presented at a BEG seminar, 1991.

"Cementation and burial history of the lower Vicksburg Formation, McAllen Ranch field, Hidalgo County, South Texas": presented to Bowling Green State University, Department of Geology, Bowling Green, Ohio, 1991.

"Petrography and diagenesis of the lower Vicksburg Formation, McAllen Ranch field, Hidalgo County, South Texas": presented to Ball State University, Department of Geology, Muncie, Indiana, 1991.

Edgar H. Guevara

"Wilcox reservoirs in the Lake Creek gas unit, Montgomery County, Texas."

"Geological characterization of Wilcox (Eocene) gas reservoirs, Lake Creek field, Montgomery County, Texas: an analog to outcrops of the Ferron Sandstone (Cretaceous), Utah": presented to the Reservoir Characterization Contractor Meeting of the Gas Research Institute Geoscience Project Area in Physical Sciences, Lakeway, Texas, 1990.

"The Secondary Gas Recovery project and Lake Creek field—a companion study": presented to the Workshop on Characterization and Quantification of Geologic and Petrophysical Heterogeneity in Fluvial Deltaic Reservoirs, organized by the Gas Research Institute and the Bureau of Economic Geology, Austin, Texas, 1990.

"Stratigraphic architecture of the Wilcox G reservoir, Lake Creek unit, Texas: results from the Secondary Gas Recovery project and implications for parallel research on outcrops of the Ferron Sandstone": poster presentation at the Shaly Sandstone Reservoir Characterization Project Advisor Meeting, Gas Research Institute, Houston, Texas, 1991.

"Reserve growth potential in deltaic reservoirs: Lake Creek unit, Texas": combined poster-core display: presented at GRI-BEG's short course titled "Infield gas reserve growth potential: Gulf Coast sandstone reservoirs (Frio, Vicksburg, Wilcox)," Houston, Texas, 1991.

Jack D. Hall

"Sedimentary facies and petrophysical characteristics of cores from the lower Vicksburg gas reservoirs, McAllen Ranch field, Hidalgo County, Texas," with R. P. Langford, J. D. Grigsby, W. E. Howard, and J. Maguregui: presented at the Gulf Coast Association of Geological Societies 40th Annual Meeting, Lafayette, Louisiana, October 17–19, 1990.

"Digital images of core photographs," with W. E. Howard: presented at the SPE Petroleum Computer Conference, Houston, Texas, July 19–22, 1992. Also presented at two SPWLA luncheons, one SIPES luncheon, and Amoco Research Center in Tulsa, Oklahoma.

Bob A. Hardage

"Advanced petrophysical methods for improved formation evaluation": presented at A Forum on Improved Oil and Gas Recovery, Houston, Texas, 1991.

"Imaging thin Frio gas reservoirs": presented to the Society of Exploration Geophysicists, Development and Production Forum, Big Sky, Montana, 1992.

"Technology transfer program for independent oil and gas operators": presented at Texas Independent Producers and Royalty Owners meetings, Fort Worth and Los Colinas, Texas, 1992.

"Principles of crosswell reflection imaging": presented to the Geophysical Society of Tulsa, Tulsa, Oklahoma, 1992.

"Status of seismic activity at Stratton fields": presented to Union Pacific Resources, Fort Worth and Bishop, Texas, 1992.

"Three-dimensional seismic technology": presented to Mitchell Energy, The Woodlands, Texas; to Cross Timbers Oil Company, Fort Worth, Texas; and to Occidental Petroleum, Midland, Texas, 1992.

William E. Howard

"Shale porosity—its impact on well log modeling and interpretation," with D. L. Luffel and E. R. Hunt: presented at the SPWLA 13th Annual Logging Symposium, June 11–14, 1989.

"Sedimentary facies and petrophysical characteristics of cores from the lower Vicksburg gas reservoirs, McAllen field, Hidalgo County, Texas," with R. P. Langford, J. D. Grigsby, J. D. Hall, and J. Maguregui: Gulf Coast Association of Geological Societies 40th Annual Meeting, Lafayette, Louisiana, October 17–19, 1990.

"Identification of bypassed gas reserves through integrated geological and petrophysical techniques: a case study in Seeligson field, Jim Wells County, South Texas," with L. A. Jirik and D. L. Sadler: SPE Gas Technology Symposium, Houston, Texas, January 23–25, 1991.

"Use of the enhanced density and microresistivity logs in interpreting diagenetic facies in Tertiary Gulf Coast sandstones," with R. P. Langford and J. D. Grigsby: presented at the SPWLA 33rd Annual Symposium, Oklahoma City, Oklahoma, 1992.

"Digital images of core photographs," with J. D. Hall: presented at the SPE Petroleum Computer Conference, Houston, Texas, July 19–22, 1992.

Lee A. Jirik

"Reservoir heterogeneity in Seeligson field, South Texas: development of recompletion and candidates in compartmentalized and bypassed gas zones": presented at a BEG seminar, 1989.

Dennis R. Kerr

"Fluvial sedimentology of middle Frio Formation (Oligocene), Jim Wells, Kleberg, and Nueces Counties, South Texas."

"Fluvial architecture and reservoir heterogeneity in the Oligocene middle Frio of South Texas": presented at a BEG seminar, 1990.

"Microresistivity imaging applications for the assessment of gas reservoir compartments in fluvial deposits of the Middle Frio Formation": presented at Geological Aspects of Borehole Imaging Conference sponsored by Society of Professional Well Log Analysts, Houston, Texas, 1991.

Richard P. Langford

"Relationship between geology and production, lower Vicksburg deltaic reservoirs, McAllen Ranch field, Hidalgo County, Texas."

"Depostional environment and reservoir properties of Oligocene Vicksburg Formation gas reservoirs, McAllen Ranch field, Hidalgo County, Texas."

"Deposition and deformation of deltas in the lower Vicksburg Formation (Oligocene), South Texas Gulf Coast": presented at a BEG seminar, 1991.

"Architecture of middle Frio fluvial deposits": presented at a BEG seminar, 1992.

Raymond A. Levey

"Integrated seismic-well log interpretation of onshore Frio Formation gas reservoirs: an example from Stratton field, South Texas": presented at a BEG seminar, 1991.

"Clues, techniques, and strategies for maximizing infield reserve growth of natural gas reservoirs": presented at a BEG seminar, 1992.

"An integrated geological, geophysical, and engineering study of a gas reservoir": presented to the Society of Exploration Geophysicists, Development and Production Forum, Durango, Colorado, 1991.

"Vertical seismic profile applications for definition of reservoir heterogeneity—South Texas, Vicksburg, and Frio sandstones: a Secondary Gas Recovery project": presented to the Houston Geological Society, Houston, Texas, 1991.

"Infield natural gas reserve growth joint venture—results in 1990": presented to the Project Advisors meeting organized by the Gas Research Institute, Houston, Texas, 1991.

"Research in secondary gas recovery": presented to Oxy U.S.A., Inc., Technical Conference, Houston, Texas, 1991.

"Future directions of the infield natural gas reserve growth joint venture": presented to Gas Research Institute, Chicago, Illinois, 1991.

"Gas research programs at the Bureau of Economic Geology": presented to the Texas Independent Producers and Royalty Owners Association, Austin, Texas, 1991.

"Secondary gas recovery research": presented to Marathon Oil Company, Oxy U.S.A., Inc., Texaco U.S.A., Mobil Exploration Producing Company, ARCO Oil and Gas Company, U.S. Geological Survey, Soviet Union Ministry of Oil and Gas, Petroleos de Venezuela, S.A., and Halliburton Geophysical Services, Austin, Texas, 1991.

Briefing to representatives of the Texas Independent Producers and Royalty Owners Association on Gas Research Programs at the Bureau of Economic Geology, Austin, Texas, 1991.

"Natural gas reserve replacement through infield reserve growth: an example from Stratton field, onshore Texas Gulf Coast Basin": presented to the Third International Reservoir Characterization Technical Conference, Tulsa, Oklahoma, 1991.

"Potential gas reserve growth in Texas: examples from Gulf Coast reservoirs": presented at A Forum on Improved Oil and Gas Recovery, Wichita Falls and Dallas, Texas, 1991.

"Infield gas reserve growth: an integral part of the natural gas resource base": presented to the Fort Worth Geological Society, Fort Worth, Texas, 1992.

"Reservoir characterization for infield reserve growth in natural gas reservoirs": presented to the Gas Research Institute, Project Advisors meeting, Denver, Colorado, 1992.

"Integrated geologic and engineering analysis for identifying secondary gas in Stratton field": presented to Union Pacific Resources, Fort Worth, Texas, 1992.

"Results of the Secondary Natural Gas Recovery project": presented to Maxus Exploration Company, Amarillo, Texas, 1992.

"Secondary natural gas recovery: targeted technology applications for infield reserve growth": presented to the Gas Research Institute/U.S. Department of Energy Technical Advisory Committee meeting, Houston and Austin, Texas, 1992.

"Applications of secondary gas research in a mature gas field": presented to Pintas Creek Oil Company, Corpus Christi, Texas, 1992.

"Results of the Secondary Natural Gas Recovery project: targeted technology applications for infield reserve growth": presented to Union Pacific Resources, Bishop, Texas, 1992.

"Historical example of infield natural gas reserve growth": presented to Canadian Hunter Exploration, Ltd., Austin, Texas, 1992.

"The Secondary Natural Gas Recovery project: targeted technology applications for infield reserve growth": presented to the Electric Power Research Institute, Austin, Texas, 1992.

"Evidence and strategies for infield reserve growth": presented to the International Gas Research Conference, Orlando, Florida, 1992.

"Stratigraphic compartmentalization within gas reservoirs: examples from fluvial-deltaic reservoirs of the Texas Gulf Coast": presented to the Gulf Coast Association of Geological Societies 33rd annual meeting, Jackson, Mississippi, October 1992.

Core and log workshop: "Reservoir properties from core and log analysis of Gulf Coast sandstone gas reservoirs, an integrated approach to infield reserve growth in Frio, Vicksburg, and Wilcox sandstones," J. M. Vidal and W. E. Howard (ResTech), and R. A. Levey, R. P. Langford, and J. D. Grigsby (The University of Texas at Austin, Bureau of Economic Geology): presented to 33rd Annual Symposium of the Society of Professional Well Log Analysts (SPWLA), Oklahoma City, Oklahoma, June 14, 1992.

"Infield gas reserve growth potential: Gulf Coast sandstone reservoirs, a short course, GRI–DOE and State of Texas," presented by the Bureau of Economic Geology, The University of Texas at Austin. Several presentations in Texas during 1992.

"Effect of fibrous illites on permeability measurements from preserved cores obtained in lower Wilcox Group gas sandstones, Lake Creek field, Montgomery County, Texas," J. M. Vidal, D. L. Luffel, J. Hawkins (ResTech), and J. D. Grigsby and J. M. Mendenhall (The University of Texas at Austin, Bureau of Economic Geology): presented to the Gulf Coast Association of Geological Societies 33rd annual meeting, Jackson, Mississippi, October 1992.

"A case study of thin bed evaluation in the Frio Formation, Stratton field, Texas," J. M. Vidal (ResTech), for The University of Texas at Austin, Bureau of Economic Geology: presented to the Society of Professional Well Log Analysts Conference on Thin Bed Evaluation, Taos, New Mexico, October 1991.

"Formation evaluation for identifying secondary gas resources: examples from the middle Frio, onshore Texas Gulf Basin," José M. Vidal and W. E. Howard (ResTech), and R. A. Levey (The University of Texas at Austin, Bureau of Economic Geology): presented to NIPER–DOE Third International Reservoir Characterization Technical Conference, Tulsa, Oklahoma, November 1991.

Project Short Courses and Workshops

A series of seven full-day short courses, two full-day core workshops, and one half-day seismic course were presented by the SGR project on behalf of the DOE, GRI, and State of Texas from October 1991 through November 1993.

Project Short Courses

"Infield Gas Reserve Growth Potential: Gulf Coast Sandstone Reservoirs (Frio, Vicksburg, Wilcox)": presented by the Bureau of Economic Geology, The University of Texas at Austin, Research and Engineering Consultants, and ResTech, Inc.

In cooperation with: Houston Geological Society

Locations: Houston, Texas; Corpus Christi, Texas; Midland, Texas; San Antonio, Texas; New Orleans, Louisiana

Dates:	October 29, 1991	Houston, Texas
	October 31, 1991	Houston, Texas
	January 16, 1992	Houston, Texas
	April 21, 1992	Corpus Christi, Texas
	April 28, 1992	Houston, Texas
	May 12, 1992	Midland, Texas
	November 5, 1992	New Orleans, Louisiana
	November 13, 1992	San Antonio, Texas

Project Core Workshops

"Reservoir Properties from Core and Log Analysis of Gulf Coast Sandstone Reservoirs: an Integrated Approach to Infield Growth in Frio, Vicksburg, and Wilcox Sandstones": presented by the Bureau of Economic Geology, The University of Texas at Austin.

Host Organization: Gulf Coast Association of Geological Societies (GCAGS)

Location: Austin, Texas

Date: October 15, 1991

"Reservoir Properties from Core and Log Analysis of Gulf Coast Sandstone Reservoirs: an Integrated Approach to Infield Growth in Frio, Vicksburg, and Wilcox Sandstones": presented by the Bureau of Economic Geology, The University of Texas at Austin, and ResTech, Inc.

Host Organization: Society of Professional Well Log Analysts

Location: Oklahoma City, Oklahoma

Date: June 14, 1992

SEISMIC Short Course

"Onshore 3-D Seismic Technology for Increased Gas Recovery"

Host Organizations: Houston Geological Society and Geophysical Society of Houston

Location: Houston, Texas

Date: November 4, 1993

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Ambrose, W. A., Grigsby, J. D., Hardage, B. A., Langford, R. P., Jirik, L. A., Levey, R. A., Collins, R. E., Sippel, M. A., Howard, W. E., and Vidal, J. M., 1992, Secondary natural gas recovery: targeted technology applications for infield reserve growth in fluvial reservoirs in the Frio Formation, Seeligson field, South Texas: The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the Gas Research Institute under contract no. 5088-212-1718, and the U.S. Department of Energy under contract no. DE-FG21-88MC25031, Report No. GRI-92/0244, 200 p.

Bebout, D. G., Weise, B. R., Gregory, A. R., and Edwards, M. B., 1982, Wilcox reservoirs in the deep subsurface along the Texas Gulf Coast: their potential for production of geopressured geothermal energy: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 117, 125 p.

Collins, R. E., and Lord, M. E., 1992, Simulation system for compartmented gas reservoirs: targeted technology applications for infield reserve growth: Research & Engineering Consultants, Inc., prepared for The University of Texas at Austin, Bureau of Economic Geology; GRI topical report for the Gas Research Institute under contract no. 5088-212-1718; and the U.S. Department of Energy under contract no. DE-FG21-88MC25031, Report No. GRI-92/0104, 75 p.

Finley, R. J., Fisher, W. L., Seni, S. J., Ruppel, S. C., White, W. G., Ayers, W. B., Jr., Dutton, S. P., Jackson, M. L. W., Banta, N., Kuuskraa, V. A., McFall, K. S., Godec, M., and Jennings, T. V., 1988, An assessment of the natural gas resource base of the United States: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 179, 69 p.

Finley, R. J., Guevara, E. H., Jirik, L. A., Kerr, D. R., Langford, R. P., Wermund, E. G., Zinke, S. G., Collins, R. E., Hower, T., Lord, M., Howard, W. E., and Ballard, J. R., 1990, Secondary natural gas recovery: targeted technology applications for infield reserve growth: The University of Texas at Austin, Bureau of Economic Geology, annual report prepared for the Gas Research Institute under contract no. 5088-212-1718, 194 p.

Fisher, W. L., and McGowen, J. H., 1967, Depositional systems in the Wilcox Group of Texas and their relationship to occurrence of oil and gas: Gulf Coast Association of Geological Societies, Transactions, v. 17, p. 105–125.

Galloway, W. E., 1977, Catahoula Formation of the Texas Coastal Plain: depositional systems, composition, structural development, ground-water flow history, and uranium distribution: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 87, 59 p.

Galloway, W. E., Hobday, D. K., and Magara, Kinji, 1982, Frio Formation of the Texas Gulf Coast Basin—depositional systems, structural framework, and hydrocarbon origin, migration, distribution, and exploration potential: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 122, 78 p.

Grigsby, J. D., and Kerr, D. R., 1991, Diagenetic variability in middle Frio Formation gas reservoirs (Oligocene), Seeligson and Stratton fields, South Texas: Gulf Coast Association of Geological Societies Transactions, v. 41, p. 308–319.

Grigsby, J. D., Guevara, E., Levey, R. A., Sippel, M. A., Howard, W. E., and Vidal, J. M., 1992, Targeted technology applications for infield reserve growth in deltaic sand-rich, low- to conventional-permeability reservoirs in the Wilcox Group, Lake Creek field, Texas: topical report prepared for the Gas Research Institute under contract no. 5088-212-1718, Report No. GRI-92/0471, 95 p.

Guevara, E. H., and Grigsby, J. D., 1992, Deltaic deposits of the Wilcox Group in the Houston Embayment: example from Lake Creek field, *in* Levey, R. A., ed., Core and log analysis of depositional systems and reservoir properties of Gulf Coast natural gas reservoirs: an integrated approach to infield reserve growth in Frio, Vicksburg, and Wilcox sandstones: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 92-7, p. 45–52.

Guven, N., Hower, W. F., and Davies, D. K., 1980, Nature of authigenic illites in sandstone reservoirs: Journal of Sedimentary Petrology, v. 50, p. 761–766.

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Appendix A: 1989 DOE/METC Conference

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

1. CONTRACT NUMBER: DE-FG21-88MC25031

CONTRACTOR: Bureau of Economic Geology
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METC PROJECT MANAGER: Gary V. Latham

CONTRACT PERIOD OF PERFORMANCE: September 1, 1988 to August 30, 1991

2. SCHEDULE/MILESTONES:

Program Schedule

	1988				1989							
	S	O	N	D	J	F	M	A	M	J	J	A
Task 1.0 Methodology for Choosing Study Areas (Sandstones)												
Evaluation of Operator Activity	—	—	—	—	—	—	—					
Initial Simulator Configuration	—	—	—	—	—	—						
Initial Field Screening	—	—	—	—	—	—						
Refined Field Screening	—	—	—	—	—	—	—	—				
Task 2.0 Untapped Compartments: Integrated Characterization of Candidate Reservoirs (Sandstones)												
Geological Characterization	—	—	—	—	—	—						
Development of Cross Section Frameworks					—	—	—	—	—			
Mapping of Target Reservoirs							—	—	—	—	—	—
Engineering Characterization				—	—	—	—	—	—	—	—	—

	1988 S	O	N	D	1989 J	F	M	A	M	J	J	A
Task 3.0 Formation Evaluation for Bypassed Gas Zones												
Geological Support for Formation Evaluation										—	—	
Sample Analysis for Shaly Sandstone Evaluation									—	—	—	—
Task 4.0 Interwell Extrapolation and Related Deeper Pools												
Subregional Stratigraphic Analysis							—	—	—	—	—	
Field-Scale Analysis of Deeper Play Components											—	—

3. <u>OBJECTIVES</u>:

Reserve growth from existing reservoirs is a major source of oil reserve additions. Therefore, it is appropriate to determine the potential for incremental natural gas recovery using new approaches to reservoir characterization. In the last 10 years, characterization of the internal geometry of reservoirs, mainly oil reservoirs, has demonstrated a higher degree of compartmentalization than previously recognized. This compartmentalization is primarily a function of depositional system and, secondarily, of the structural and diagenetic history of the reservoir after deposition. Where significant geologic variation occurs, untapped or bypassed reservoir compartments remain to be drained of natural gas by drilling or recompleting strategically placed development wells. Deeper pool potential, which is closely related to producing depositional systems, can be better defined by sequence stratigraphy and also offers opportunities for increased reserves. It is the objective of this project to define and demonstrate the potential for incremental gas recovery, or gas reserve growth potential, within existing nonassociated gas fields.

Approaches to defining the distribution of unrecovered resources by depositional system and methods for maximizing their recovery will be developed and tested as part of the Secondary Gas Recovery (SGR) Project. This project, a joint effort of the Gas Research Institute (GRI), the U.S. Department of Energy (DOE), and the State of Texas, will focus specifically on Texas natural gas reservoirs as a major subset of the Nation's natural gas resource base.

Results of this project will better enable producers to economically recover this discovered but undeveloped natural gas resource through integrated geological, engineering, petrophysical, and geophysical assessments. Depositional systems studies of major gas reservoirs in South Texas have already indicated the complexity of fluvial-deltaic reservoirs in the Frio Formation; thus, Frio reservoirs will be a likely first target for improved recovery in the first half of the SGR project. A second target is likely to include heterogeneous carbonate reservoirs either in East Texas or in the Permian Basin of West Texas. Geological, engineering, and geophysical data will be integrated to provide models of reservoir continuity and pressure distribution in representative reservoirs in these gas plays.

4. BACKGROUND STATEMENT:

This study will involve delineation of gas resources in untapped compartments, of bypassed reservoirs in existing wells, and of closely related deeper pool targets. The latter target will be defined with more extensive use of seismic sequence analysis as a predictive tool. The project will be field oriented and will involve cooperative data collection with operators drilling current development wells as a cost-effective means of acquiring data and performing interim tests of research results. In this way the eventual users of the project technology are involved in its development. Knowledge gained from the cooperative wells will be used to design Staged Field Experiment (SFE) wells that are specifically drilled for research purposes, to confirm or challenge research progress on the largest scale, and to test novel applications of newly developed technologies.

Duration of the Secondary Natural Gas Recovery project will be 3 years divided into two periods. Cooperative data collection early in each of the two periods will define sites for the research wells. The initial 18 months will focus on sandstone reservoirs, culminating with the drilling of an SFE well and analysis of results. Next, a carbonate reservoir will be selected, and the special requirements of advanced production technologies in that reservoir lithology will be investigated within an 18-month period.

5. PROJECT DESCRIPTION:

BYPASSED RESERVOIRS

Initial emphasis of the project will be on bypassed gas in sandstone reservoirs. Where contemporaneous subsidence and deposition of fluvial-deltaic reservoirs has taken place, 30 (or more) vertically stacked reservoirs have been deposited. Not all of these have been fully drained, particularly those in which sand-rich depositional axes are separated by floodplain mudstones and poorly interconnected crevasse splay deposits. Operators have taken advantage of recompletions in many such fields using selected cased-hole logs.

For this SGR project, an advanced cased-hole logging suite will be applied in conjunction with geological modeling designed to fully characterize the interwell area. This modeling will better define the interconnection of producing facies and incorporate engineering assessments of pressure histories, production decline rates, and other key parameters. With the drilling of new wells to deeper targets in the field being studied, open-hole pressure data can be collected to help assess the potential for recompletions in older wells. Core will be recovered for analysis of diagenetic heterogeneities and for calibration of open-hole and cased-hole logs. The overall result will be a fully integrated reservoir analysis that can be used to define the distribution of bypassed gas. Initiating the program with study of bypassed reservoirs and working in an interval with abundant well control will complement the main emphasis of the study, that of untapped compartments.

Untapped Compartments

Depositionally heterogeneous reservoirs are likely to have untapped compartments where wells have been sited largely on the basis of geographic-spacing rules rather than on geologic variation. Because this phenomenon has been increasingly demonstrated in oil reservoirs, a key question for this SGR study is whether natural gas, having lower viscosity than oil, is subject to similar incomplete recovery due to reservoir heterogeneity. We believe that heterogeneity within the 320- to 640-acre spacing typical of gas reservoirs with conventional permeability allows for untapped and incompletely drained compartments in selected depositional systems.

Data and interpretations made during the initial investigation of bypassed gas will be used in developing reservoir models necessary for targeting untapped compartments. Defining component facies from abundant well data within gas-bearing depositional systems containing bypassed gas is a key first step in assessing (1) the degree of continuity of reservoir types between wells, (2) the relationship between reservoir size and the expected area of gas drainage, given specific reservoir quality parameters, and (3) the likelihood that undetected heterogeneities are affecting gas production. These heterogeneities, if sufficient barriers to flow, lead to untapped compartments within reservoirs that can be predicted using geological, engineering, and geophysical approaches at the facies, reservoir, and field scale.

Deeper Pool Potential

This project will investigate the deeper pool development potential of gas resources in deeper reservoirs that are closely related in depositional system to currently productive shallower reservoirs. Development of deeper pool potential emphasizes vertical reservoir sequences below producing intervals in related depositional systems. Entirely different depositional systems involve more of an element of deeper pool exploration that is not a significant focus of this research program. The deeper pool potential being considered here is therefore termed "related deeper pool" resource potential. In many fields, few wells have penetrated the deeper parts of producing depositional sequences below well-established limits of gas production. A sounder basis for predicting related deeper pools will help maximize recovery from known natural gas fields.

6. RESULTS/ACCOMPLISHMENTS:

GEOLOGICAL INVESTIGATIONS

The results to date, within the first 6 months of the project, focused on geological and engineering screening of potential areas of study, operator contacts and monitoring of drilling and permitting activity in the areas of interest, configuration of engineering tools and testing approaches, and use of existing data to further refine approaches to shaly sandstone reservoir evaluation. With the initial focus on sandstones, operator activity reports and personal contacts with operators active in South Texas were utilized to determine planned activity in the Frio fluvial-deltaic play along the Vicksburg Flexure and in the Vicksburg deltaic sandstones of the Rio Grande Embayment. These two plays essentially overlap, with the Vicksburg reservoirs lying below and partially transitional with the overlying Frio. The Frio fluvial deltaic play ranks third in cumulative production (11.8 Tcf through 1986) and the Vicksburg deltaic play ranks fifteenth in cumulative production (3.5 Tcf through 1986) among 72 established gas plays in Texas. Because of their known heterogeneity, both lateral and vertical, these reservoirs are particularly suited to the SGR project.

Field Screening and Operator Activity

Discussions have been held with five operators active in South Texas, and written project descriptions have been placed with two others. Two operators are considering project participation in the near term, one during drilling of a deeper pool test in the Frio in Seeligson field and another during conventional development drilling in the Vicksburg in McAllen Ranch field. The Frio test will pass through a series of some 20 productive sands that will be examined for bypassed gas potential. Seeligson and McAllen Ranch are among more than a dozen fields that were evaluated in the screening process.

McAllen Ranch Field, Hidalgo County

McAllen Ranch field was discovered in 1960 when the Shell A. A. McAllen No. 1 well was completed as a gas producer. Shell initiated a successful development program in which 14 wells were drilled (no dry holes) from late 1960 through 1963. More than 130 wells have been drilled in the field to date, with production from 33 Vicksburg reservoirs. Six wells were completed in 1988.

A growth-fault-related anticline characterizes the McAllen Ranch field area. Structure in the upper Vicksburg is relatively simple, with an anticlinal nose formed on the downthrown side of a major growth fault. Middle and lower Vicksburg faults form elongate closures within the field, and dip-reversal becomes more pronounced with depth.

The lower Vicksburg in McAllen Ranch field includes several sandstone intervals up to 1,000 ft thick displaying upward-coarsening log patterns. A net sandstone isopach map of the uppermost sandstone section of the lower Vicksburg shows a dip-elongate depositional axis and general lobate pattern that suggest distributary and channel-mouth bar deposition. Detailed studies of individual sandstones in McAllen Ranch field have identified one or more distributary-channel systems that terminate in the area, resulting in well-to-well heterogeneity. The middle Vicksburg also contains several upward-coarsening sandstone sequences up to 400 ft thick.

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

McAllen Ranch field has produced more than 770 Bcf of gas from 33 Vicksburg reservoirs ranging in depth from 7,000 to 15,000 ft. Fourteen reservoirs have produced more than 10 Bcf each; the largest producer is the McAllen Ranch Vicksburg S, S reservoir with cumulative production of more than 124 Bcf.

Porosity and permeability data from McAllen Ranch field indicate low reservoir quality. The majority of whole-core samples show permeabilities less than 1 md; only a small percentage have permeabilities greater than 10 md. Porosities range from about 16 to 25 percent. Because of the generally poor reservoir quality, fracture stimulation techniques are used in about half of the completions; however, reservoirs often flow 1 to several million cfd of gas prior to fracture treatment.

Seeligson Field, Jim Wells and Kleberg Counties

Seeligson field is located in Jim Wells and Kleberg Counties, about 5 mi north of the town of Premont, Texas. Seeligson field covers approximately 50 mi^2, and was discovered in 1937 when the Magnolia A. A. Seeligson No. 7 was drilled to a depth of 8,141 ft, at which point hydrocarbons were encountered in non-unit Zone 22-5. More than 1,000 wells have since been drilled in the field, and cumulative production exceeds 2.5 Tcf.

Seeligson field is located along the eastern margin of the extensive Vicksburg Fault Zone. The field is bounded updip by a large northeast-southwest trending growth fault that offsets Frio sands several hundred feet. The eastern, downdip boundary of the field is defined by the limits of production. Within the field, subsidiary highs occur on the primary rollover anticline that defines the structural configuration of the field.

Over 130 Frio and Vicksburg reservoirs have been documented across Seeligson field. These multiple, vertically stacked, dominantly fluvial sandstones exhibit varying degrees of complexity. Although each zone is generally less than 100 ft thick, the majority are composite intervals of several genetic cycles. Aggregate sandstone patterns illustrate dominantly dip-parallel depositional trends generally indicative of fluvial environments. The interbedded sandstones and shales reflect the diversity of environments of deposition within each zone.

Seeligson field has produced approximately 2.5 Tcf of gas from 131 Vicksburg and Frio reservoirs ranging in depth from 4,000 to 8,500 ft; 27 reservoirs have produced more than 10 Bcf each. Most of the gas is trapped on the crest of the rollover anticlinal structures associated with the major Vicksburg growth fault, although the contribution of stratigraphic controls (sand-body pinch-outs or facies changes) is substantial in terms of macroscopic heterogeneity.

Reservoir quality in Frio sandstones within Seeligson field is expected to be good. Whole-core analyses indicate porosities of 19 to 27 percent and permeabilities from 60 to 1,100 md in point bar and crevasse splay sandstones. Reservoir stimulation techniques are generally limited to acidizing. Recompletions with pressures 1,000 psi above average reservoir pressure show compartmentalization of fluvial splay sandstones.

ENGINEERING INVESTIGATIONS

The identification of reservoir compartmentalization and selection of optimum infill drilling sites based on engineering criteria is a process involving several steps. First, available field pressure and production data are analyzed for evidence of compartmentalization. This is accomplished using P/Z versus cumulative production type curves. The deviation of actual P/Z behavior from the ideal straight line behavior is an indicator of compartmentalization. With these type curves, certain physical properties of the drained and undrained compartments, and the barrier itself, can be quantified.

The engineering assessment of a reservoir, or field, is being integrated with the geological evaluation to generate a refined interpretation. Then, hypotheses for the reservoir configuration, developed to that point, will be confirmed through transient pressure well testing in the field.

Initial Simulator Configuration

Two reservoir simulators were configured to address natural gas reservoirs exhibiting the heterogeneous depositional character typical of those in the onshore Gulf Coast Basin. Boast II, a three-dimensional, three-phase simulator will be used in the more complex, larger scale studies while a fully implicit, Newton-Raphson model will be used in the smaller scale, one- or two-dimensional investigations. Whereas much has been written on characterizing heterogeneous reservoirs and generating input data for simulation studies, little research has addressed simulation techniques for these reservoirs. How one represents a heterogeneity in permeability in the discretized format of a simulator can greatly influence the results of the simulation.

An important element in these simulations is the manner in which a well is represented in the simulator. A representation was evolved to be consistent with the gas reservoir systems to be studied. As most gas wells are operated at a constant flowing bottomhole pressure, rather than a constant volumetric rate, it is critical to have the same capabilities in any simulators that will be used. Unfortunately, most of the common well representation techniques described in the literature are not applicable to the more complex grid systems that will be used in modeling these heterogeneous reservoirs. Thus, more intricate schemes were investigated and implemented in the simulators.

Demonstration of Simulation and Well Testing

Using the previously configured Newton-Raphson reservoir simulator, various example studies were conducted to construct materials which can be used to demonstrate to industry operators how undrained compartments can be identified using certain analytical techniques. This involved configuring a "typical" reservoir and constructing sample P/Z curves to illustrate the anticipated behavior. These simulations also provide type curves which will be used with field data to identify compartmentalization.

Background and Analytical Model

To provide insight into the effect of specific reservoir parameters on P/Z plots and to guide the design of these simulations of compartmentalization, an analytical model was formulated. This model is a linear reservoir partitioned into two compartments, having pore volumes V_1 and V_2, by a plane low-permeability barrier of thickness L and permeability K_b (figure 1). Only Volume No. 1 is drained by a well, this having constant rate q_s (scf).

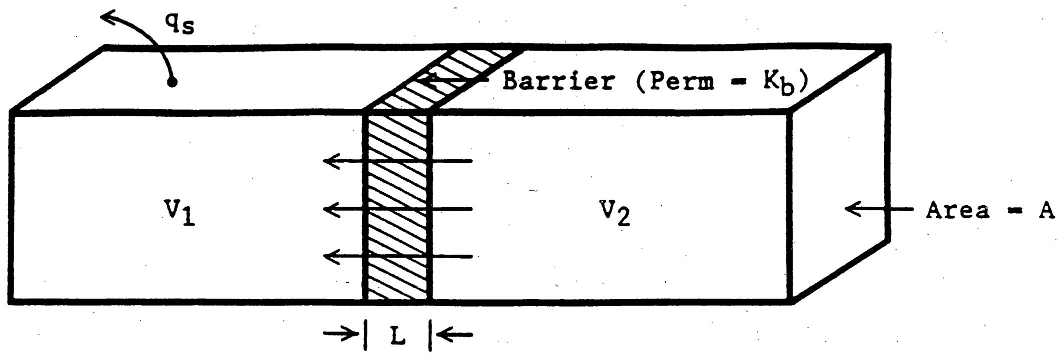

Figure 1

Differential equations constructed using the conservation of mass of gas for each chamber, with the real-gas equation-of-state and Darcy's law for flow through the barrier, yield a solution for static P/Z versus time at the well in the drained compartment. This analytical solution treats gas viscosity, μ_i, and compressibility, C_i, as constant at their initial values, indicated by the subscript i.

With this analytical solution, it is shown that P/Z versus cumulative production, $q_s t$, appears as in the figure below (figure 2).

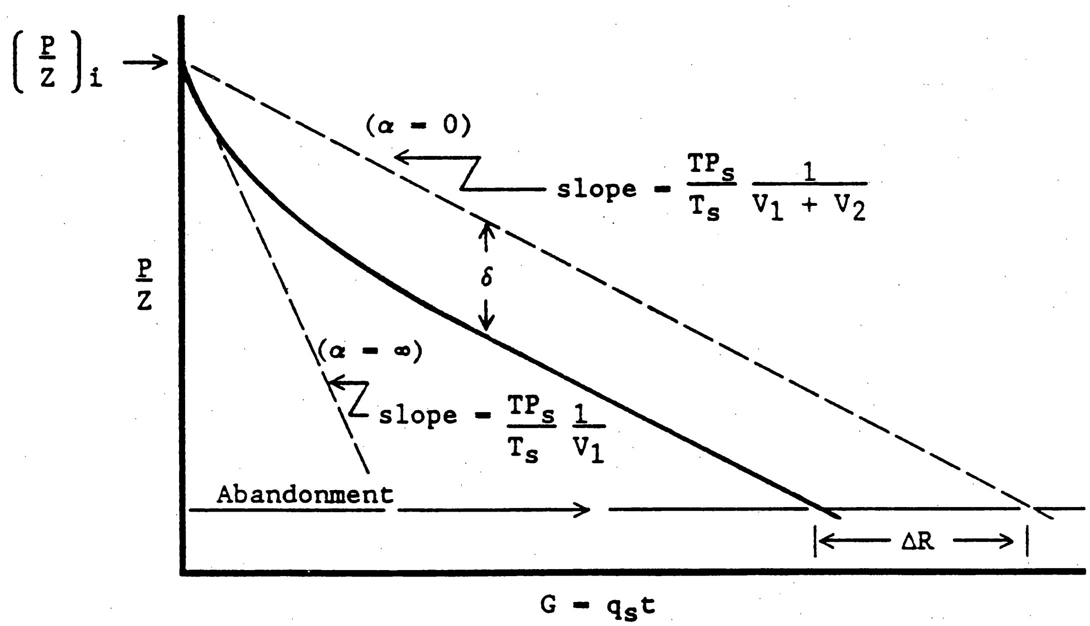

Figure 2

This curve is characterized by two dimensionless groups given by

$$\alpha = \frac{q_s \mu_i C_i L \, TP_s}{K_b A \, T_s} \quad \text{and} \quad \beta = \frac{V_1}{V_2}$$

Here the upper dotted line is the solution that exists for no barrier, $\alpha = 0$, having slope inversely proportional to $V_1 + V_2$ while the lower dotted line is the solution for an impermeable barrier, $\alpha = \infty$, having slope inversely proportional to V_1. This solution shows that the actual ultimate recovery is reduced below that with no barrier by an amount

$$\Delta R = \frac{q_s \mu C L V_2^2}{K_b A (V_1 + V_2)}$$

Thus, the more the well is drawn down (higher q_s) the lower is the ultimate recovery. This also corresponds to a downward displacement of the straight line portion of the graph by an amount δ proportional to $\alpha/(\beta + 1)^2$. Therefore, it was anticipated that the two slopes and δ might be determinable from plots of field data and these could be used to determine parameters of a compartmentalized reservoir. However, the simulation studies described below demonstrated that this might not always be possible.

Simulation Studies of Compartmentalization

The Newton-Raphson simulator described above was configured for the same systems in the analytical study, but the compartments had finite permeability K, and the pore volume of the barrier was included. Also, μ and C were proper functions of pressure everywhere. Typical solutions are exhibited as a family of curves in which the dimensionless group α is the varied parameter (figure 3). These results reveal that under certain configurations the curves produce the anticipated shape and are readily analyzable.

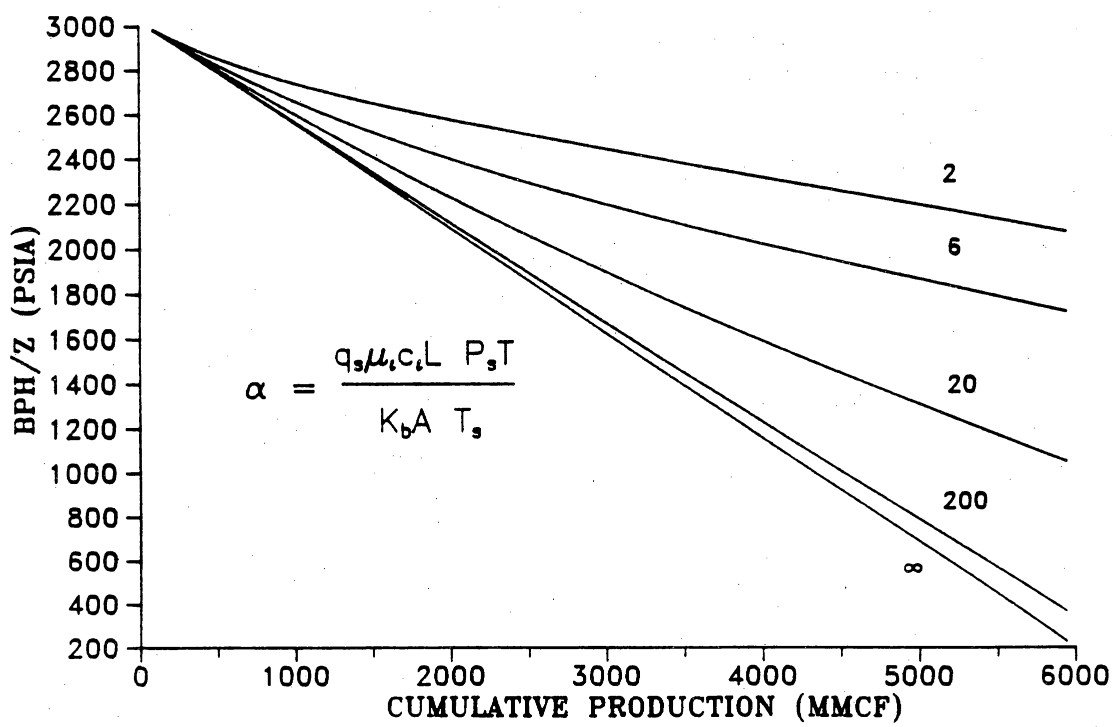

Figure 3. Effect of Alpha on P/Z Curve (BETA = 1/3).

However, under other conditions the approach to the asymptotic straight line discussed above may not occur until very late in the production life of the well. Consequently, early well history could not be exploited in the manner outlined above. Thus, efforts are in progress to develop supplemental analyses of other aspects of production data to complement this type of analysis.

In order to reduce this P/Z curve analysis to a practical format, the generation of families of type curves has been undertaken. These are dimensionless P/Z versus cumulative production curves for various values of the dimensionless parameters α, β, and γ where γ is K_b/K. It is to be noted that for a sufficiently small value of γ, (high reservoir permeability), these graphs are essentially independent of γ. These graphs can then be used with field data to determine V_1, V_2, and K_bA/L for a well.

At this time the simulator is essentially complete and a schedule of computer runs is being designed to provide answers to practical questions about well testing.

Field Studies and Screening

Initial engineering studies were conducted on Stratton field in Nueces, Kleberg, and Jim Wells Counties and on McAllen Ranch field in Hidalgo County, Texas. Stratton field includes Frio fluvial-deltaic reservoirs generally similar to those of Seeligson field described above. Owing to the complex nature of both fields and the large amount of data associated with each, it was first necessary to develop some unique engineering techniques that would aid in characterizing the reservoir production quality. Methods were developed that provide a "quick-look" at the production decline character of a well and the pressure decline history within a reservoir. The techniques allow for qualitative observations regarding historical production and provide much insight into reservoirs exhibiting possible compartmentalization. These techniques were applied to both fields, and several reservoirs were identified as candidates for further investigation.

FORMATION EVALUATION AND PETROPHYSICAL INVESTIGATIONS

New interpretation strategies using recently introduced state-of-the-art logging tools will be pursued for evaluating reservoirs within 5 ft of the borehole. Emphasis will be placed on integrating all available field and well data with cased hole logging data for a unique view of the reservoir. In addition, several evolving technologies will be pursued for imaging the reservoir at distances greater than 5 ft from the cased borehole. These technologies include borehole gravity surveys and through-casing resistivity measurements. Formation evaluation using accurate consistent near borehole and far well bore through casing is the research objective.

In addition to the cased-hole formation evaluation, a study will be undertaken to determine the contribution of neighboring shales to gas reserves. Although the industry has made significant progress in understanding and modeling shaly sandstone reservoirs using formation evaluation, there are still some major problems. For example; in log analysis it is common to assume that the fractional shale volume associated with sand in a shaly sandstone bed carries with it an associated fractional porosity that is the same as that found in adjacent shale beds. Further, it is usually presumed that the shale pore volume contains only immobile water, that it cannot contain free gas regardless of how the shale is distributed in the sand (laminar, dispersed, or detrital), and regardless of the capillary pressure level in the sandstone body. As a result, in shaly sandstone gas reservoirs, in place and recoverable gas may be significantly higher than would normally be estimated using traditional shaly sandstone evaluation methods. The objective of the combined core and log analysis study is to provide the basis for a new model for evaluating the shaly sands that properly recognizes the type of shale distribution in the sandstone and reflects the shale properties found in adjacent shales.

In the absence of key data collected in open hole, cased-hole logging technologies are the most economic option for additional data acquisition in existing fields. Cased-hole logging programs will be tailored around pulsed neutron logs, full waveform acoustic logs, and spectral gamma-ray logs. Certain borehole and near-borehole environments (such as low-porosity and low-salinity conditions) force existing cased-hole tools beyond their accuracy limits. In these cases, better use of full waveform acoustic technology for through casing porosity determination, a new method for resistivity measurements for through casing saturation determination and borehole gravity survey technologies, will be critical.

7. FUTURE WORK:

Project work is now moving from preliminary field screening, both geological and engineering, to refined field screening during which further detailed reservoir data will be collected from company files and during cooperative well studies with operators. The focus of initial data collection will be on bypassed reservoirs during deeper pool tests. By working in a data-rich environment, multiple reservoirs can be examined for their geometry and for continuity of natural gas flow between wells, with the result that untapped compartments can be more effectively defined. Completion records, production histories and current reservoir pressures collected in cooperative wells will be utilized. Results will define the degree of macroscopic (between-well) heterogeneity that acts to restrict flow of natural gas between wells in fluvial-deltaic settings. In addition, full suites of open-hole logs will be calibrated against cased-hole logs and vertical seismic profiling (VSP) will be used to image between-well reservoir volumes.

The first cooperative well program is expected to be carried out in Seeligson field, South Texas. There, Mobil Exploration & Producing U.S. Inc. will be drilling two deeper pool tests approximately 3,000 ft apart in a heretofore underdeveloped part of the field where new seismic lines have recently been run. A cooperative program including coring, logging, extensive formation pressure testing, and VSP work has been proposed. Initial work in one well will be closely followed by a second well that will provide an opportunity to examine pressure continuity across the intervening distance, and possibly in relation to surrounding producing wells. Most of the reservoirs being tested are part of a unit operated by Sun Exploration and Production Co., which is also cooperating in the SGR project. All these activities are aimed at screening potential locations for a future research well, as outlined in the project plan, as well as conducting specific project tasks.

8. REFERENCE:

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Appendix B: 1991 DOE/METC Conference

Infield Reserve Growth/Secondary Natural Gas Recovery: Targeted Technology Applications For Infield Reserve Growth - Year Two Report

CONTRACT INFORMATION

Contract Number	DE-FG21-88MC25031
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Principal Investigators	Robert J. Finley Edgar H. Guevara Raymond A. Levey
METC Project Manager	Gary V. Latham
Period of Performance	September 1, 1988 to August 30, 1991
Schedule and Milestones	

FY 1990 Program Schedule

	S	O	N	D	J	F	M	A	M	J	J	A
Task 1.0 Methodology for Choosing Study Areas (Carbonates) (Task 1.0 completed for Sandstones)												
Evaluation of Operator Activity												
Initial Simulator Configuration	Not initiated for carbonates											
Initial Field Screening												
Refined Field Screening	Not initiated for carbonates											
Task 2.0 Untapped Compartments: Integrated Characterization of Candidate Reservoirs (Sandstones)												
Geological Characterization												
Development of Cross Section Frameworks	Completed											

	S O N D J F M A M J J A
Mapping of Target Reservoirs	
Engineering Characterization	
Task 3.0 Formation Evaluation for Bypassed Gas Zones	
Geological Support for Formation Evaluation	
Sample Analysis for Shaly Sandstone Evaluation	
Task 4.0 Interwell Extrapolation and Related Deeper Pools	
Subregional Stratigraphic Analysis	
Field-Scale Analysis of Deeper Play Components	No activity

OBJECTIVES

In the last decade, characterization of the internal geometry of reservoirs, mainly oil reservoirs, has demonstrated a higher degree of compartmentalization than previously recognized. This compartmentalization is primarily a function of the depositional system and, secondarily, of the structural and diagenetic history of the reservoir after deposition. The objective of this project is to define the potential for incremental gas recovery based on better understanding of depositional and diagenetic heterogeneity within known nonassociated gas reservoirs. Where significant geologic variation occurs, untapped or bypassed reservoir compartments remain to be drained of natural gas by drilling or recompleting strategically placed development wells. Deeper pool potential, which is closely related to producing depositional systems, can be better defined by sequence stratigraphy and also offers opportunities for increased reserves. However, because deeper pool drilling is part of standard industry practice more related to exploration than development, it is not a major focus of this project.

Approaches to defining the distribution of unrecovered resources by depositional system and methods for maximizing their recovery are being developed and tested as part of the Infield Reserve Growth/Secondary Gas Recovery (SGR) Project. This project, a joint effort of the Gas Research Institute (GRI), the U.S. Department of Energy (DOE), and the State of Texas, is focused specifically on Texas natural gas reservoirs as a major subset of the Nation's natural gas resource base.

Results of this project will better enable producers to economically recover this discovered but undeveloped natural gas resource through integrated geological, engineering, petrophysical, and geophysical assessments. Depositional systems studies of major gas reservoirs in South Texas have already indicated the complexity of fluvial-deltaic reservoirs in the Frio Formation; thus, Frio reservoirs have become a major target for demonstrating improved recovery potential in sandstones. A second target will include heterogeneous carbonate reservoirs either in East Texas or in the Permian Basin of West Texas.

BACKGROUND STATEMENT

To date, the project has operated primarily in four fields in the Gulf Coast Basin that produce from different formations under different conditions of depth, pressure, and permeability. Primary emphasis has been on non-geopressured, conventional permeability reservoirs like the Frio Formation in Seeligson and Stratton fields. These reservoirs were deposited as part of a bedload-rich fluvial system that fed a major deltaic depocenter in South Texas. The geopressured, low-permeability reservoirs of the Vicksburg Formation were the objective of studies of deltaic reservoirs at McAllen Ranch field, also in South Texas. Reservoirs of the Wilcox Group in Lake Creek field in the northern part of the Texas Gulf Coast Basin include fluvial-deltaic gas reservoirs that vary from conventional to low permeability.

Cooperative data collection with operators drilling development wells has occurred in all these fields. Considerations of geology, amenability to engineering testing, depth, and cost indicate that the Frio Formation will be most appropriate for drilling of a project-operated Field Experiment well to confirm or challenge concepts developed during cooperative data collection, and to test current state-of-the-art and newly developed technologies in an integrated manner. It is anticipated that the Field Experiment well for sandstones will be drilled early in 1991.

PROJECT DESCRIPTION

Bypassed Reservoirs

Significant emphasis of the project to date has been on bypassed gas in sandstone reservoirs; a second phase of the research will deal with carbonate reservoirs. Where contemporaneous subsidence and deposition of dominantly fluvial sandstone reservoirs has taken place, 30 (or more) vertically stacked reservoirs have been deposited, as in the Frio Formation of South Texas. Not all of these have been fully drained, particularly those in which sand-rich fluvial axes are separated by floodplain mudstones and poorly interconnected crevasse splay deposits.

For this project, engineering pressure testing and an advanced cased-hole logging suite are being applied in conjunction with geological modeling to fully characterize the interwell area. This modeling better defines the interconnection of producing facies and incorporates engineering assessments of pressure histories and production decline rates. Drilling of new wells to deeper targets in the field being studied allows open-hole pressure testing to be used to define unrecovered gas in bypassed compartments. Core has defined diagenetic heterogeneities for calibration of open-hole and cased-hole logs and has shown that channel margins, because of either channel lag material or cementation, may have lower permeability than the bulk of the fluvial sand body. The overall result will be a fully integrated reservoir analysis that can be used to define the distribution of bypassed gas.

Untapped Compartments

Depositionally heterogeneous reservoirs are likely to have untapped compartments where wells have been sited largely on the basis of spacing rules or for protection against drainage along lease boundaries rather than on geologic variation. A key question for this study is whether natural gas, having lower viscosity than oil, is subject to incomplete recovery due to reservoir heterogeneity. Evidence suggests that heterogeneity within the 320- to 640-acre spacing typical of many gas reservoirs with conventional permeability allows for untapped and incompletely drained compartments in heterogeneous depositional systems.

Data and interpretations made during the initial investigation of bypassed gas are being used in developing reservoir models necessary for targeting untapped compartments. Defining component facies from abundant well data within gas-bearing depositional systems containing bypassed gas is a key first step in assessing (1) the degree of continuity of reservoir types between wells, (2) the relationship between reservoir size and the expected area of gas drainage, given specific reservoir quality parameters, and (3) the likelihood that undetected heterogeneities are affecting gas production. These heterogeneities, if sufficient barriers to flow, lead to untapped or incompletely drained compartments within reservoirs that can be predicted using geological, engineering, and geophysical approaches at the facies and reservoir scale. Geophysical techniques, especially vertical seismic profiling (VSP), reverse VSP, and cross borehole tomography, offer the prospect of more directly defining the geometry of target reservoir compartments.

Deeper Pool Potential

This project originally included evaluation of gas resources in deeper reservoirs that are closely related in depositional system to currently productive shallower reservoirs. However, industry has established approaches to such development, and the project Technical Advisory Committee has determined that deeper pool potential should be de-emphasized.

RESULTS

Results from the first 1.5 years of study indicate that both stratigraphic and diagenetic compartments affect natural gas recovery in sandstone gas reservoirs of the Texas Gulf Coast Basin. Variations in both the scale of heterogeneity and depositional environment of the reservoir system play an important role in gas reserve growth potential.

Scales of Heterogeneity: An Example From McAllen Ranch Field

Research efforts have focused on the overpressured Oligocene Vicksburg S-reservoirs of the Rio Grande Embayment. Stratigraphic and geophysical analysis of McAllen Ranch field identified a series of six deltaic sandstone intervals. Geologic interpretation of core and well logs from two cooperative wells (Shell Western E&P, Inc. McAllen Ranch B-17 and B-18) indicate facies heterogeneity and diagenetic boundaries across the field. Characterization of these reservoirs has been addressed through integrated petrophysical, engineering, and geological analyses.

Petrophysical Analysis. Confined sand-shale, overpressured sequences typical of deep Vicksburg reservoirs are ideal for formation evaluation research in shaly sands. Logging and coring programs on the cooperative wells provided a high quality data set to test shaly sand models using core analysis data to confirm log calculations. The logging program consisted of phaser induction, litho-density, neutron, gamma ray, digital long spaced acoustic, and wireline pressure tester logs. Approximately 240 ft of core from the "S sandstone" interval was recovered and measurements were made for restored state porosity, permeability, capillary pressure, cation exchange capacity, cementation and saturation exponents, x-ray diffraction analysis, and thin section analysis. Use of measured core water saturations to confirm log-derived water saturations is not commonly done, but an opportunity to do so existed here because the wells were drilled using oil-based mud.

Several water saturation models were evaluated and a Waxman-Smits model was used to make this comparison. Clay weight percent was taken from x-ray diffraction analysis and used as a basis to determine volume of clay from well log clay indicators. Cation exchange capacity (CEC) was determined by correlating measured CEC values with x-ray diffraction clay fraction. This allowed computation of a continuous CEC based on the log-core correlations. Porosity was calculated using a fixed grain density of 2.66 grams per cc. This allowed the best correlation to core porosity. Water saturations were calculated using the Waxman-Smits model with the log-derived CEC, cementation and saturation exponents taken from special core analysis, and a formation water resistivity supplied by the field operator.

Formation evaluation results show several important points. Capillary pressure measurements indicate core water saturation in some cases are too low. The initial mercury injection capillary pressure measurements performed by the operator in the sandstones show good general agreement. However, in the siltstones above the S-4 reservoir, water saturations are generally higher (up to 30 percent) than measured core water saturations. This is a significant difference but they are confirmed using measurements performed by Core Laboratories. Using the log derived values of porosity, and parameters taken from core analysis (CEC, m, n), calculated water saturations agree with the capillary pressure water saturations. The difference between these capillary pressure and measured core water saturations is being evaluated. Porosity and water saturations are displayed together with the results of the core analysis and raw log curves (Fig. 1). The capillary pressure water saturations are displayed using a common water level of 13,600 ft. The differences are easily seen. Agreement between log and core data are generally good, with the exception of the water saturation measurements.

Engineering Assessment. Engineering questions have been addressed that are unique to the character of the low-permeability, overpressured Vicksburg reservoirs of South Texas. While a tank-like, compartment model has been useful in assessing reservoir performance in the more permeable reservoirs (such as Stratton and Seeligson fields), this model has been shown to be inappropriate for McAllen Ranch reservoirs. Because of the low effective permeability of the reservoirs (~0.05 md), a low-permeability barrier (~0.0005 md) at distances on the order of 500 to 1,000 ft is not readily detectable in well behavior and performance represented by a tank-like model. Therefore, a two-dimensional, finite element model has been used to evaluate performance of hydraulically fractured wells in low-permeability reservoirs of the Vicksburg play like those in McAllen Ranch. The model provided accurate simulation of wells completed by hydraulic fracturing and applied the geologic reservoir model and the permeability-thickness and hydrocarbon porosity-thickness data derived from well log analysis. This simulation included five producing wells in a domain bounded in a wedge-shaped area by two intersecting faults. In addition to observed initial pressures in these wells, wireline pressure test results from three other wells were used to calibrate the model. A history match was achieved only by inserting a low-permeability barrier across a portion of the reservoir as indicated in the accompanying figure showing the finite element grid (Fig. 2). Thus, there is evidence for permeability barriers in McAllen Ranch reservoirs, but in view of low reservoir permeability these could only be potentially demonstrated by very long-term (years) well interference, and not by single well performance.

A principal hypothesis that has developed as part of the study of McAllen Ranch is that a creep-compaction drive mechanism plays a significant role in determining well performance. For example, it is observed that wells exhibit significant increases in production rates for a significant period following curtailment of production. This production phenomenon is attributed to time-delayed compaction, or creep, of the overburden as pressure support is removed by fluid production from the overpressured reservoir rather than to reservoir heterogeneity. Thus, porosity in the reservoir declines with time as the overburden slowly "flows" to re-establish mechanical equilibrium.

To demonstrate that creep-compaction can account for observed well behavior following curtailment, the finite element model was modified to simulate a time-delayed porosity decline determined by pressure history in each volume element. The resulting model exhibited behavior like that seen in the field.

Geological Heterogeneity. There are two potential sources at different scales for additional infield reserves in Vicksburg gas reservoirs of McAllen Ranch field. The most likely sources for additional completions are distributary channel-fill sandstones that are laterally discontinuous. Since sandstone intervals are stacked, recompletion opportunities are present, but age of wellbore tubular goods may make such recompletions technically difficult. Stacked distributary channels are prevalent in the proximal parts of deltaic, progradational intervals that make up lower Vicksburg reservoirs similar to the S reservoir. Therefore, in other gas fields, infill recovery efforts could target the proximal portions of deltaic packages where stratigraphic variability is highest. Areas laterally adjacent to the distributary channels (McAllen Ranch B-area) contain more continuous shoreface and delta front sandstones. This offers less potential for infill gas recovery and greater lateral continuity exists. Additional potential reserve growth is partially a function of completion practices. Single completions from numerous stacked sandstones assume there is a single drainage radius. Because the reservoir quality and resultant drainage radii vary among reservoirs and within a single reservoir resources may remain between wells in selected sandstones. This is one aspect of compartmentalization of the reservoir.

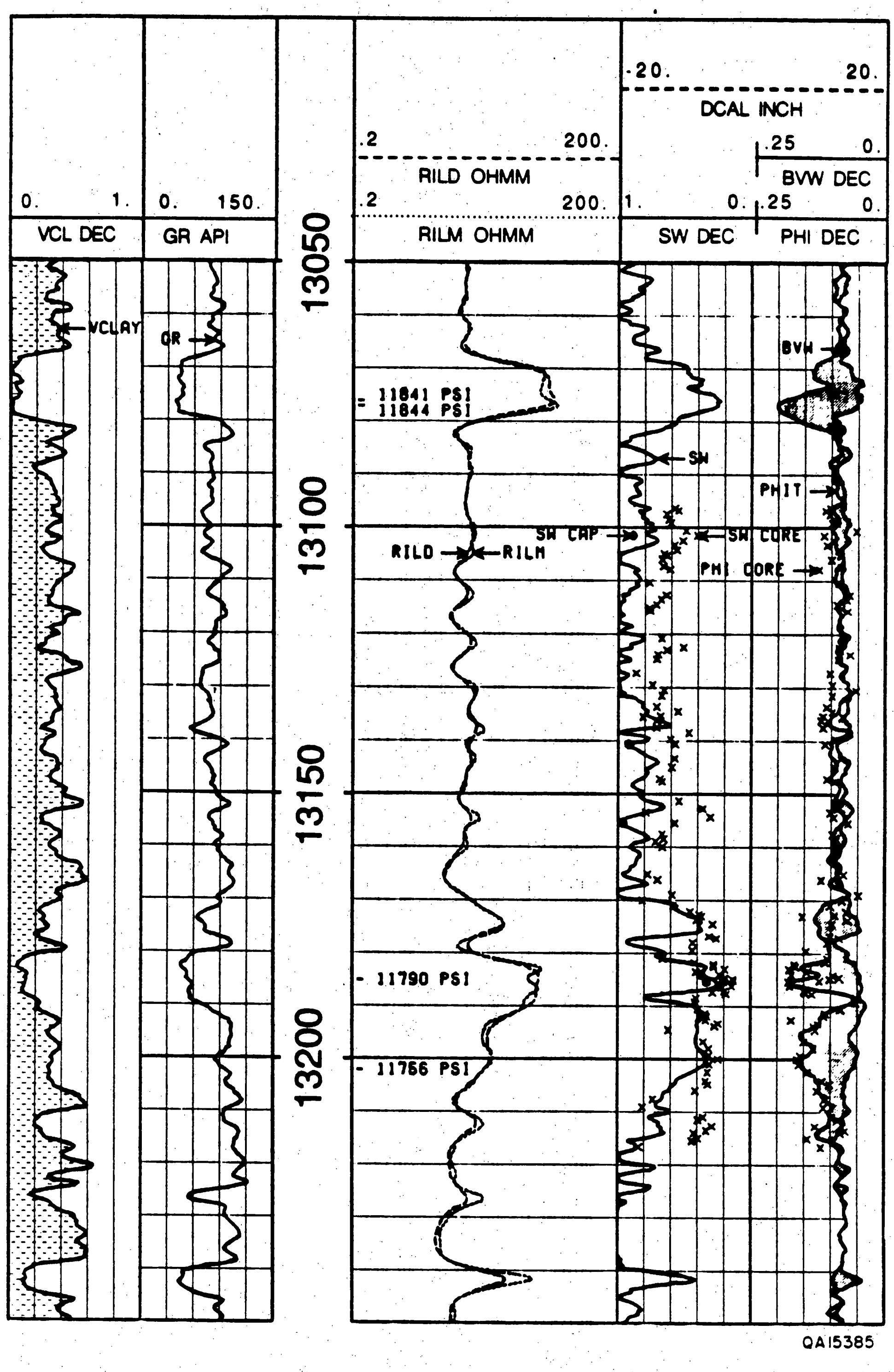

Figure 1. Comparison Of Core Analyses And Log Derived Properties From The Shell Western E&P, Inc. McAllen Ranch B-18 Cooperative Well.

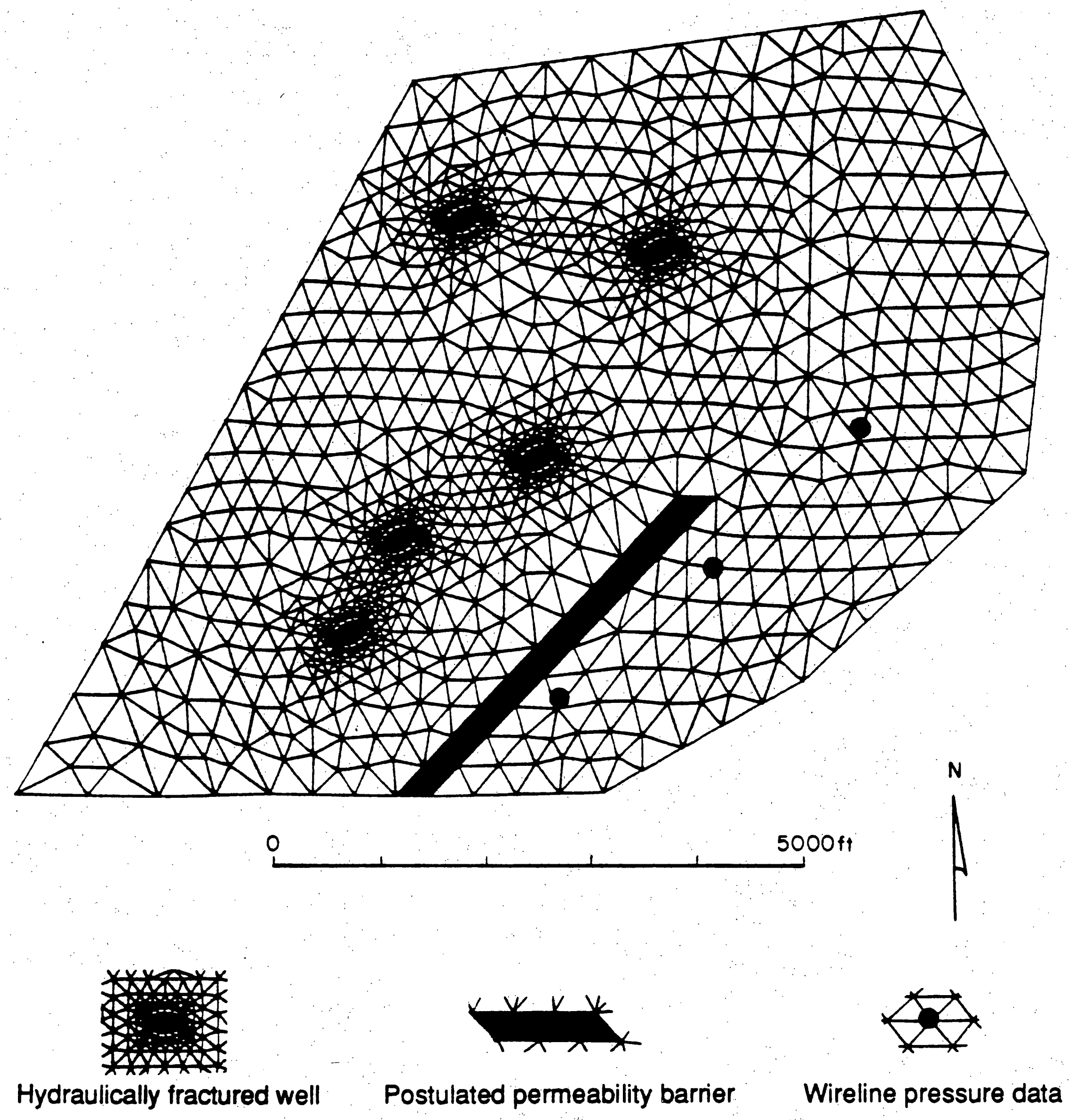

Figure 2. Two-Dimensional Finite Element Grid Utilized To Model The S-4 Reservoir In The B-Area Of McAllen Ranch Field.

The most important cause of variability in the S reservoir is diagenesis which creates variation in drainage radii for different sandstones in the same well. The development of secondary porosity within the S reservoir sandstones is the most important diagenetic control on reservoir volume and permeability. Large variations in porosity and permeability correlate with changes in diagenesis but not with depositional changes. Calculations of projected production and original gas in place indicate highly varying drainage radii. Recoveries based upon extrapolated rate decline data were compared with material balance projections based upon volumetric estimates of initial gas-in-place. Comparisons for seven wells in the S-4 reservoir indicate that significant variations between wells are seen, and that interpretation of results is strongly dependent on accurate estimates of initial water saturation and the assigned porosity cut-off that determines contributing reservoir volume.

Assessment of Facies Heterogeneity in Fluvial Reservoirs: Seeligson and Stratton Fields

Research on fluvial reservoirs has focused on the normally pressured Oligocene middle Frio reservoirs along the Vicksburg Flexure of South Texas. Lithologic and facies heterogeneity of middle Frio fluvial reservoirs are a function of changes in the stratigraphic architecture which can vary not only among different fields but within a single reservoir level of the same field. A spectrum of fluvial architectural styles has important implications for reservoir compartmentalization (Fig. 3). A variation from laterally stacked to vertically stacked channel systems was documented through closely spaced well log correlations across the 2,500-ft thick middle Frio section. High resolution stratigraphic sequence analysis using well logs suggests that incised valley fill can be identified within a nonmarine depositional setting. These gas reservoirs are composed of sandstone-rich channel-fill and splay deposits interstratified with levee and floodplain mudstones. Separate channel-fill deposits have lateral dimensions of 2,500 ft and thicknesses of 30 ft contrasted with splay deposits up to 2 mi across and up to 20 ft in thickness.

Seeligson Field Experiment. The influence of fluvial reservoir heterogeneities on the behavior of gas flow will be examined through field experiments and reservoir engineering modeling in Seeligson field. The experiment is centered on five wells in a 1 mi^2 area adjacent to two project cooperative wells (Mobil Nos. 247 and 248) drilled in 1989. Results from closely spaced geophones (30 ft) in a modification of standard VSP acquisition techniques indicate improved resolution of sandstone reservoirs compared to conventional 2-D surface seismic and VSP acquisition. An extensive cross-discipline data collection program including cross borehole tomography, near and far offset VSP's, reverse VSP's, 3-D surface seismic, cased-hole logging, borehole gravimetry, and both single and multiple well pressure testing will commence in the fourth quarter of 1990. A borehole gravity survey in one well will test the applicability of borehole gravity in old wells to determine bypassed gas distribution and porosity.

Interference testing planned for five wells will evaluate reservoirs of Zones 19-C and 15 by measuring pressure changes in observation wells caused by staggered production pulses in nearby wells. Prior to the multiple well interference testing, single-well tests will measure current reservoir pressures, near-well permeability, and completion efficiency. Information from these tests will be used to calibrate computer simulation of the interference pulse test. Reperforation and downhole equipment modifications will be required in some wells to open zone 19C reservoir sands to the wellbore and allow the installation of pressure recording equipment. Down-hole shutoff equipment is required to avoid wellbore storage effects and yield test results of sufficient sensitivity.

Current Activities in Stratton Field. During a cooperative well (Union Pacific Resources Elliff No. 40) in Stratton field, extensive core and borehole scanner measurements (Formation Microscanner, or FMS) were collected. The evaluation of methods to interpret thin beds continues, in order to find possible pay zones in thin sand bodies. A comparison of the microscanner images with core produced excellent correlation, indicating utility of FMS images for stratigraphic interpretation in non-cored zones. Wireline pressure test pressures were very useful to define depleted or partially depleted zones. Core analysis results are available from seven reservoirs in three wells and statistical analysis of core permeability versus core porosity at net overburden pressure has been used to derive a permeability index from computed log porosity. Preliminary petrophysical results have been generated for porosity, shaliness, and hydrocarbon saturation.

Preliminary findings on the computed results of twelve wells analyzed to date indicate that sand thickness, shale laminations in sand bodies, and porosity change laterally for the same zones in adjacent wells. Screening of valid wireline tester shut-in pressures within the same stratigraphic reservoirs indicate that wide variations in pressure continuity exists laterally within the same reservoir. Chronological analysis of formation pressure readings indicate wells with >70% of virgin reservoir pressure. In addition it is not uncommon for sequentially later pressure tests to have higher initial pressure than previous adjacent wells. This

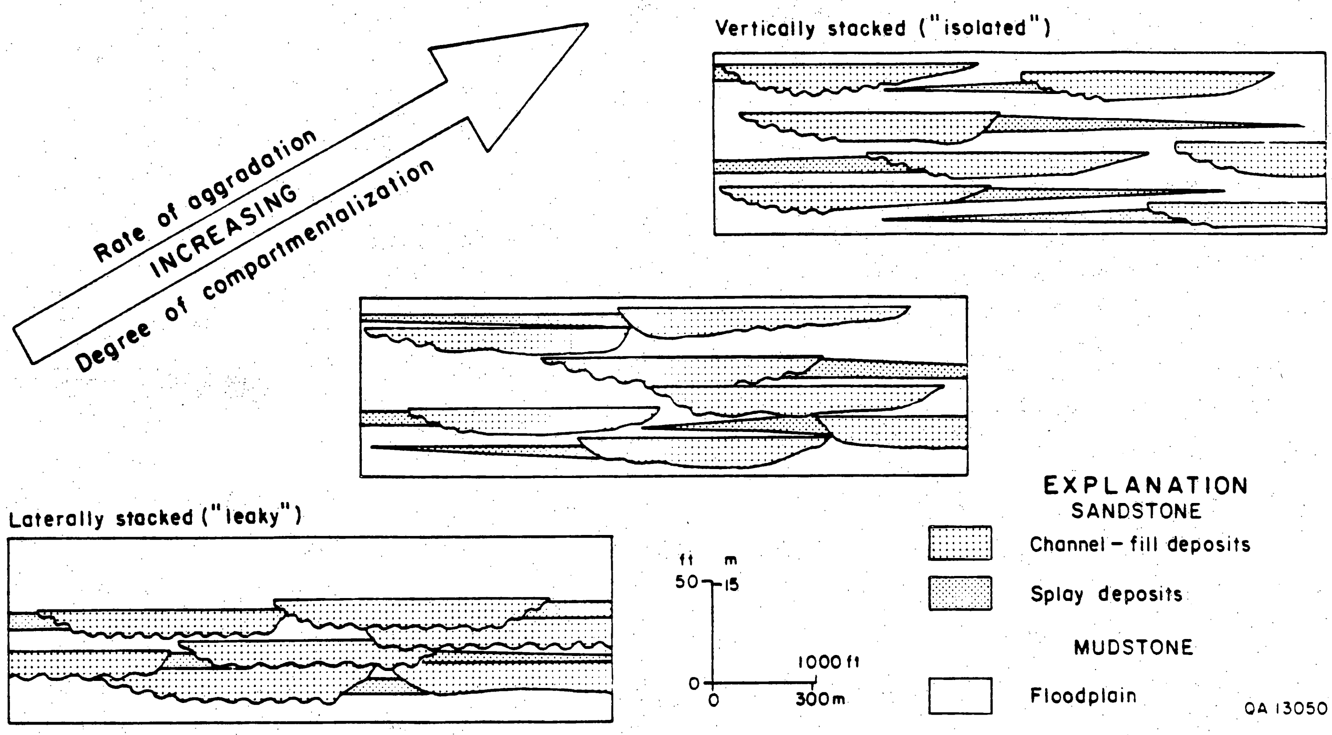

Figure 3. Schematic Diagram Illustrating Variations In Fluvial Architecture From Laterally Stacked Genetic Intervals With A Potential For Pressure Leaky Compartments To Vertically Stacked Genetic Intervals With A Potential For Pressure Isolated Compartments.

can be caused by non-uniform depletion or compartmentalization of the reservoir. Unfortunately these pressure data are not complete across all reservoirs. In future wells more shut-in pressures must be obtained to fully evaluate the impact of apparent compartmentalization on recovery and the distribution of remaining resources.

Screening Techniques For Assessment of Stratton Reservoir Heterogeneity. Public domain production data are being analyzed to identify production performance parameters which may indicate reservoir compartmentalization. In the Stratton-Agua Dulce fields, data from ~400 wells in 29 distinct reservoirs are being evaluated. The complete rate versus time decline history is being examined by an automated curve-fitting program to identify wells exhibiting evidence of pressure support interpreted as due to flow across permeability barriers. The reciprocal of initial decline rate is also being examined statistically for each reservoir as an indication of heterogeneity; this parameter is linearly proportional to the drainage volume of a well.

Detailed history matching of rate decline with a tank-like compartment model has been shown to be quite accurate for wells in several Stratton reservoirs. Production rate increase following extended curtailments is a characteristic that is represented by such models.

Engineering Techniques: Well Testing - Stratton. Single-well pressure build-up tests have been designed for five selected wells in Stratton field. These tests will incorporate a shut-in pressure build-up followed by a step-rate flow test using a high precision bottomhole gauge with surface read-out and downhole shut-off tool. These wells are in reservoirs where depositional boundaries may be detectable in the tests.

Methodology for Selecting Carbonate Study Areas. Assessment of gas reservoirs across Texas (Kosters, et. al., 1989) indicate that over 30 of the gas reserves in Texas are in Carbonate reservoirs. Regional screening results indicate that among the eight major gas plays there are 50 non-associated reservoirs with <30 Bcf. For selected west Texas and east Texas gas reservoirs P/Z data, rate-time data, and growth vintaging parameters are under consideration as field screening techniques.

FUTURE WORK

The near-term (next 2-6 months) work on the project will be directed toward three major goals: (1) completion of a report on the McAllen Ranch reservoir studies; (2) initiation and completion of the intensive data collection effort planned for Seeligson field within which multiple data types will be obtained on a coordinated basis, and (3) evaluation of compartmentalization in Stratton field that can lead to the selection of a project research well location. The latter is a project requirement in the near term and one that will allow extensive data collection that cannot be conducted in cooperative wells. Siting of this well must be coordinated with surrounding wells, either producing or abandoned in the reservoirs of interest, to conduct between-well engineering testing.

The preceeding three efforts and resulting analysis and reporting will conclude the bulk of the sandstone reservoir studies. Work will continue on Wilcox reservoirs at Lake Creek field, where coordination with another GRI project is ongoing, and where major cooperative activity with the field operator will occur in late 1990 or in 1991. Further work in the carbonate reservoir study area will lead to the first carbonate reservoir cooperative wells in 1991.

REFERENCES

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Kosters, E. C., Bebout, D. G., Seni, S. J., Garrett, C. M., Jr., Brown, L. F., Jr., Hamlin, H. S., Dutton, S. P., Ruppel, S. C., Finley, R. J., and Tyler, Noel, 1989, Atlas of major Texas gas reservoirs: The University of Texas at Austin, Bureau of Economic Geology Special Publication, 161 p.

Appendix C: 1992 DOE/METC Conference

Incremental Natural Gas Resources Through Infield Reserve Growth/Secondary Natural Gas Recovery

CONTRACT INFORMATION

Contract Number	DE-FG21-88MC25031
Contractor	Bureau of Economic Geology The University of Texas at Austin University Station, Box X Austin, Texas 78713 (512) 471-1534
Contractor Project Manager	Robert J. Finley
Principal Investigators	Robert J. Finley Raymond A. Levey
METC Project Manager	Gary V. Latham
Period of Performance	September 1, 1988 to August 31, 1992

Schedule and Milestones

FY92 Program Schedule

	O N D J F M A M J J A S
Task 1.0 Methodology for Choosing Study Areas	
Evaluation of Operator Activity	Completed
Initial Simulator Configuration	Completed
Initial Field Screening	Completed
Refined Field Screening	Completed
Task 2.0 Untapped Compartments: Integrated Characterization of Candidate Reservoirs (Sandstones)	
Geological Characterization	
Development of Cross Section Frameworks	Completed
Mapping of Target Reservoirs	Completed
Engineering Characterization	
Geophysical Characterization	
Task 3.0 Formation Evaluation for Bypassed Gas Zones	
Geological Support for Formation Evaluation	
Sample Analysis for Shaly Sandstone Evaluation	Completed
Task 4.0 Interwell Extrapolation and Related Deeper Pools	
Subregional Stratigraphic Analysis	
Field-Scale Analysis of Deeper Play Components	No activity

OBJECTIVES

In the last decade, characterization of the internal geometry of reservoirs, mainly oil reservoirs, has demonstrated a higher degree of compartmentalization than previously recognized. This compartmentalization is primarily a function of the depositional system and, secondarily, of the structural and diagenetic history of the reservoir after deposition. The objectives of the Infield Reserve Growth/Secondary Natural Gas Recovery (SGR) project have been:

- To establish how depositional and diagenetic heterogeneities in reservoirs of conventional permeability cause reservoir compartmentalization and, hence, incomplete recovery of natural gas.

- To document practical, field-oriented examples of reserve growth from fluvial and deltaic sandstones of the Texas gulf coast basin and to use these gas reservoirs as a natural laboratory for developing concepts and testing applications of both tools and techniques to find secondary gas.

- To demonstrate how the integration of geology, reservoir engineering, geophysics, and well log analysis/petrophysics leads to strategic recompletion and well placement opportunities for reserve growth in mature fields.

- To transfer project results to natural gas producers, not just as field case studies, but as conceptual models of how heterogeneities determine natural gas flow and how to recognize the geologic and engineering clues that operators can use in a cost-effective manner to identify secondary gas.

Where significant geologic variation occurs, untapped or bypassed reservoir compartments remain to be drained of natural gas by drilling or recompleting strategically placed development wells. Deeper pool potential, which is closely related to producing depositional systems, can be better defined by sequence stratigraphy and also offers opportunities for increased reserves by better understanding of reservoir architecture and allowing prediction of reservoir stacking patterns. However, because deeper pool drilling is part of standard industry practice more related to exploration than to development, it is not a major focus of this project.

Approaches to defining the distribution of unrecovered resources by depositional system and methods for maximizing their recovery are being developed and tested as part of the SGR project. This project, a joint effort of the Gas Research Institute (GRI), the U.S. Department of Energy (DOE), and the State of Texas, is focused specifically on Texas' natural gas reservoirs as a major subset of the Nation's natural gas resource base.

Results of this project will better enable producers to economically recover this discovered but undeveloped natural gas resource through integrated geological, engineering, petrophysical, and geophysical assessments. Depositional systems studies of major gas reservoirs in South Texas have already indicated the complexity of fluvial-deltaic reservoirs in the Frio Formation; thus, Frio reservoirs have become a major target for demonstrating improved recovery potential in sandstones.

BACKGROUND STATEMENT

To date, the project has operated primarily in four fields in the Gulf Coast Basin that produce from different formations under different conditions of depth, pressure, and permeability (Figure 1). Primary emphasis has been on non-geopressured, conventional permeability reservoirs like the Frio Formation in Seeligson and Stratton fields. These reservoirs were deposited as part of a bedload-rich fluvial system that fed a major deltaic depocenter in South Texas. The geopressured, low-permeability reservoirs of the Vicksburg Formation were the objective of studies of deltaic reservoirs at McAllen Ranch field, also in South Texas. Reservoirs of the Wilcox Group in Lake Creek field in the northern part of the Texas Gulf Coast Basin include fluvial-deltaic gas reservoirs that vary from conventional to low permeability. Studies in McAllen Ranch and Seeligson fields are complete, and documentation is either complete

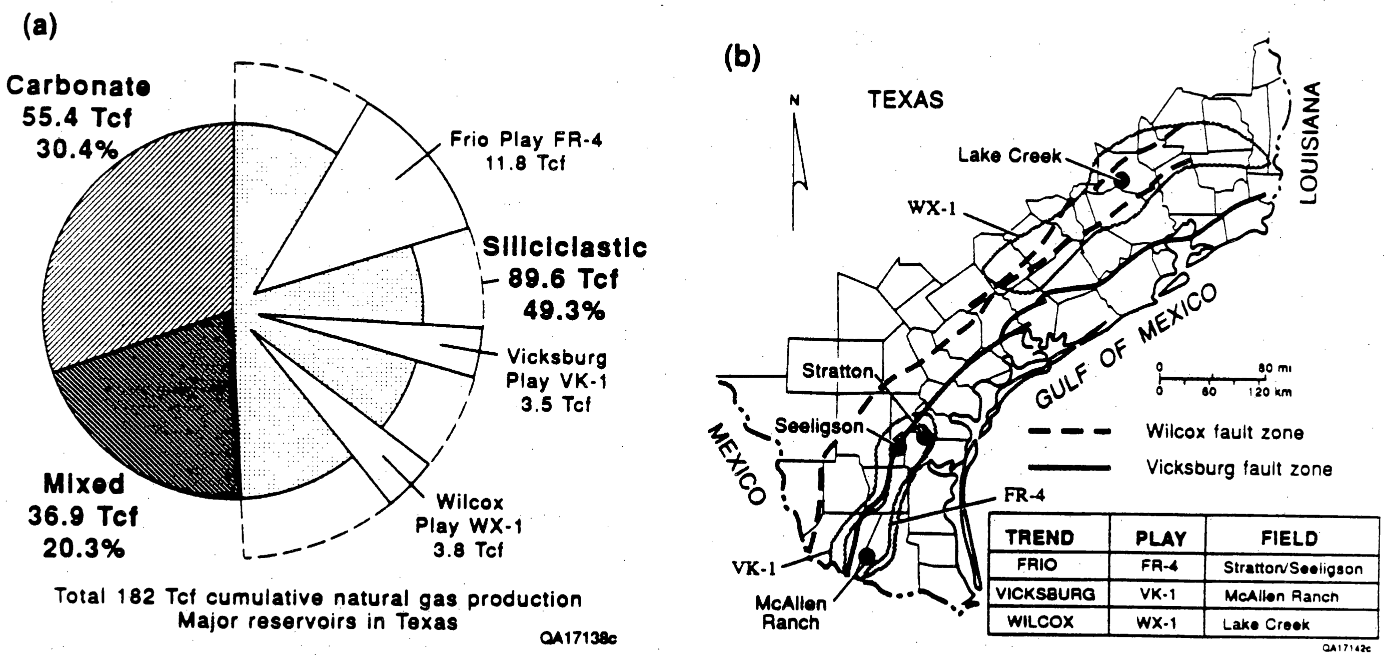

Figure 1. (a) Lithologic Distribution Of Gas Production From Major Texas Gas Reservoirs And (b) Location Map Illustrating The Boundaries Of The Three Major Gas Plays And Fields Being Investigated By The SGR Project (Modified From Kosters And Others, 1989).

(McAllen Ranch; Langford and others, 1992; Langford and Hall, 1992) or in final review (Seeligson; Ambrose and others, in preparation).

Cooperative data collection with operators drilling development wells has occurred in all these fields. Considerations of incremental resources, reservoir geology, amenability to engineering testing, depth, and cost indicated that the Frio Formation was the most appropriate for numerous multiple and single well pressure tests and geophysical studies to define heterogeneities in the interwell area. Project focus for this detailed work has been narrowed to Stratton field where extensive cooperation of the field operator, Union Pacific Resources Company, has been gained. Emphasis has been on determining the limits of flow units in a vertical stack of multiple reservoir sandstones. Extensive well testing took place in the latter half of 1991 and early 1992. Planned acquisition of a 3-D seismic survey was delayed, however, due to extensive flooding in South Texas during the winter of 1991-92 and is now scheduled for May of 1992.

PROJECT DESCRIPTION

Bypassed Reservoirs

Significant emphasis of the project to date has been on bypassed gas in sandstone reservoirs. Where contemporaneous subsidence and deposition of dominantly fluvial sandstone reservoirs has taken place, 30 (or more) vertically stacked reservoirs have been deposited, as in the Frio Formation of South Texas. Not all of these reservoirs have been fully drained, particularly those in which sand-rich fluvial axes are separated by laterally adjacent floodplain mudstones and poorly interconnected crevasse splay deposits (Jirik and others, 1991; Vidal and others, 1991).

Engineering pressure testing, a personal computer-based compartmented reservoir simulation model developed as part of the project, cased-hole logging, and both surface and downhole geophysics at the development scale are being applied in conjunction with geological modeling to fully characterize the interwell area.

This modeling better defines the interconnection of producing facies and incorporates engineering assessments of pressure histories and production decline rates. Whereas previous work has emphasized open-hole data acquisition, current and planned work has involved pressure testing by reperforating existing wells in anticipation of potential recompletions once deeper reservoirs have been depleted. Reprocessing of vertical seismic profiles (VSP's) acquired earlier in the project has better defined reservoir heterogeneities and allowed accurate ties of stratigraphy to 3-D seismic data acquired in Seeligson field. The overall result will be a fully integrated reservoir analysis that is being used to define the distribution of bypassed gas.

Untapped Compartments

Depositionally heterogeneous reservoirs are likely to have untapped compartments where previous development wells have been sited largely on the basis of spacing rules or for protection against drainage along lease boundaries rather than on geologically defined targets. A key question for this study is whether natural gas, having lower viscosity than oil, is subject to incomplete recovery due to reservoir heterogeneity. Evidence suggests that heterogeneity within the 320- to 640-acre spacing typical of many gas reservoirs with conventional permeability allows for untapped and incompletely drained compartments in heterogeneous depositional systems. Indeed, spacing between 40 to 80 acres in Stratton field has been shown to encounter both untapped and partially drained compartments in complex fluvial channel and crevasse splay facies

Data and interpretations made during the initial investigation of bypassed gas are being used in developing reservoir models necessary for targeting untapped compartments. Defining component facies from abundant well data within gas-bearing depositional systems containing bypassed gas is a key first step in assessing (1) the degree of continuity of reservoir types between wells, (2) the relationship between reservoir size and the expected area of gas drainage, given specific reservoir quality parameters, and (3) the likelihood that undetected heterogeneities are affecting gas production. These heterogeneities, if sufficient barriers to flow, lead to untapped or incompletely drained compartments within reservoirs that can be predicted using geological, engineering, and geophysical approaches at the facies and reservoir scale. Results in Stratton field have documented numerous occurrences of such heterogeneities that are the result of both depositional and diagenetic factors.

Deeper Pool Potential

As previously reported, industry has well-established approaches to deeper pool development, and the project Technical Advisory Committee has determined that deeper pool potential should not be addressed given the greater inherent difficulties in the issue of reservoir heterogeneity.

RESULTS

Reservoir Characterization

Production characteristics and measured pressure response in a laterally continuous fluvial sandstone reservoir indicates compartmented reservoir behavior even after 50 years of gas production. Reservoir pressure differences of 400 psi in adjacent wells at 40- and 80-acre completion spacing reflect compartmented reservoir behavior and are not attributable to random noise or measurement error. Multiple well tests including 12 static pressure gradient surveys and 19 transient well tests were conducted in a 480-acre project test area in the middle Frio Formation in Stratton field. Geologic evaluation of well logs indicates the test reservoir is characterized by laterally continuous sandstones deposited as fluvial channel-fill deposits constituting a reservoir that has been producing since the 1940's. Project test results demonstrate a wide variation in permeability and drainage volume among wells separated by less than 40 acres in this moderate-permeability (1-10 md) reservoir. Static reservoir pressures measured during a field-wide shut-in of the test reservoir, conducted as part of the project data acquisition in 1991, are not consistent with measurements which would be expected in a homogeneous reservoir.

Several high-productivity wells (>700 mcf/d) are producing from relatively small primary compartments (<20 acres). These wells deplete rapidly to noneconomic rates, but are gas recharged after shut-in and quickly return to high pressures and flow rates. Barriers to effective gas drainage by radial flow are attributed to both depositional (facies variability; Kerr, 1990; Kerr and Jirik, 1990) and diagenetic effects (resulting from the alteration of volcanic-glass detritus; Grigsby and Kerr, 1991; Kerr and Grigsby, 1991). Calculation of the primary and support volumes in several reservoirs within the test area show a polymodal compartment size distribution. The primary compartment distribution has a median size of 35 acres (Figure 2). This supports the conclusion that close completion spacing may be necessary to access a major incremental gas resource in these types of fluvial reservoirs.

Engineering Testing and Resource Delineation. Geologic evaluation and engineering testing of gas reservoirs in complex fluvial deposits has increased our understanding for maximizing natural gas recovery in compartmented reservoirs. Comprehensive project investigation of the middle Frio, (F-series) of gas reservoirs in Stratton field has been used to confirm the existence of incremental gas resources approaching 0.5 Bcf per completion in an area where the reservoir completion spacing is less than 80 acres. Project-designed testing in 25 wells, using both single and multiple well pressure measurements, including shut-in gradients, buildup transient well tests, and complex transient well tests with multiple drawdown and buildup periods, demonstrate how fluvial architecture affects gas recovery. Interference testing has identified compartmented behavior in mature producing reservoirs (>30 years previous production). Geologic constraints on compartment size (reservoir volume), compartment shape (reservoir form as a function of primary depositional facies), and reservoir quality (reservoir permeability affected by both primary depositional fabric and diagenesis) were determined by well testing over short time frames (i.e., days versus years of production history).

Static reservoir pressures ranging from 300 psi to 3,200 psi over a distance of 0.5 mile existed in the test area in 1988 at the onset of an aggressive infield drilling program. Project well tests in 1991-92 have discovered static reservoir pressures from 640 to 1,740 psi in a 1 square mile area. The test reservoirs within the lower third of the middle Frio formation are typical of incompletely (or poorly) drained compartments in fluvial depositional systems with permeabilities ranging from 10 to 100 md. Well tests indicate channelized flow behavior that appears to reflect the elongated shape typical of the reservoir framework associated with fluvial deposition. Both depositional and diagenetic processes create low permeability barriers that segregate the reservoir into primary and supporting compartments which require modification of traditional development practices if gas recovery is to be optimized.

Integrated Formation Evaluation and Engineering Testing

A project-derived formation evaluation methodology for middle Frio sandstone reservoirs results in a high success rate for identifying gas-bearing zones. The highest open-hole formation evaluation success rate in middle Frio gas reservoirs is obtained by going beyond the standard Archie technique or quick-look methods to determine hydrocarbon mobility. Mobility provides the additional information necessary to identify gas zones, and to minimize the chance of perforating and testing water producing zones which are costly to squeeze. The methodology was tested by comparing predicted production with well test results on nine wells in Stratton field where a total of 36 gas zones and 41 water zones have recently been tested. The methodology indicates a 91 percent success rate in finding hydrocarbon zones, and a 78 percent success rate in ruling out water zones.

Project research in cased wells indicates that a combination of pulsed neutron and full wave acoustic log is effective for identifying bypassed gas zones. In addition, the prediction of reservoir pressure was attempted using an indirect pressure measurement method derived from cased-hole logs. The cased-hole pulsed neutron count ratio was calibrated to open hole wireline shut-in pressures. Pressure predictions were tested in three project recompletion wells with limited but encouraging results. Results indicate that the method is only potentially effective in clean nonassociated gas-bearing sandstone zones with low water saturations.

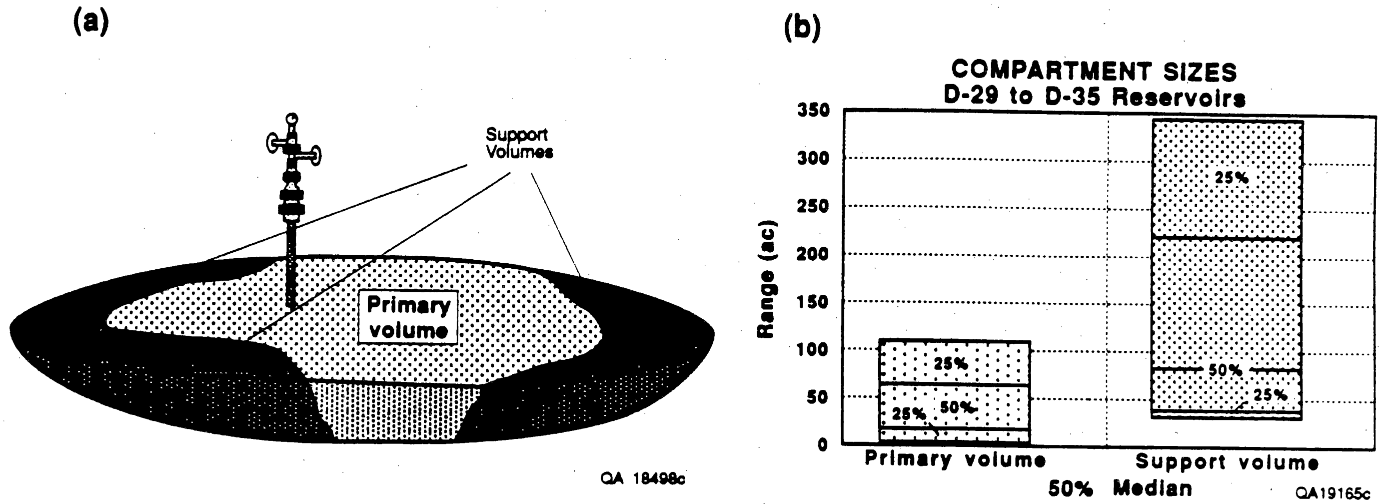

Figure 2. (a) Diagrammatic Sketch Of Relationship Between Primary And Support Volumes In A Gas Reservoir With Precise Geometry Of The Support Volumes Unspecified; (b) Percentile Plot Illustrating Primary And Support Volume Size Distribution For Fluvial Reservoirs In The North Study Area Of Stratton Field.

A Compartmented Reservoir Simulator

A new reservoir simulation system for compartmented natural gas reservoirs (Gas-Wizard or G-Wiz) was developed by the Secondary Gas Recovery (SGR) project as a reservoir management tool (Lord and Collins, 1991; Collins and Lord, 1992). A microcomputer-based, user friendly program applicable to the evaluation of natural gas reservoirs using rate and pressure data from existing wells has been developed as a marketable product for the gas industry. This product has been extensively tested in field applications, and is currently in a Beta testing stage. History matching of single well data as a two compartment system yields estimates for the pore volume of the compartment directly drained by the well, the pore volume and pressure of a supporting compartment, and the transmissibility of the barrier separating these two compartments. Thus, the model identifies and quantifies potential incremental gas resources from performance data of an existing well and can predict future performance for any specified operating conditions (Figure 3).

The reservoir compartment model can be used to determine the most effective field development strategies in compartmented reservoirs. This model has been used to develop stochastic simulations of multi-well, multi-compartment reservoirs in which compartment pore volumes and barrier transmissibilities are assigned by a Monte Carlo technique to create multiple reservoir realizations. One application evaluated the effects of several critical variables on the effectiveness of infield development in increasing ultimate recovery. Variables included the compartment size, barrier transmissibility, well spacing, and field development rate. Forward modeling with the G-Wiz model allows an operator to estimate resource and potential revenue under different reservoir conditions and operating scenarios.

Reservoir Geophysics

Reservoir imagery using 3-D surface seismic and spatially coincident vertical seismic profiles can be effective for addressing stratigraphic, and potentially diagenetic, compartmentalization in natural gas reservoirs. Detailed 3-D seismic images acquired in Seeligson field have successfully imaged thin fluvial sandstones (less than 20 ft net reservoir thickness) at greater than 5,000 ft subsurface depth in the middle Frio formation. Vertical seismic profile

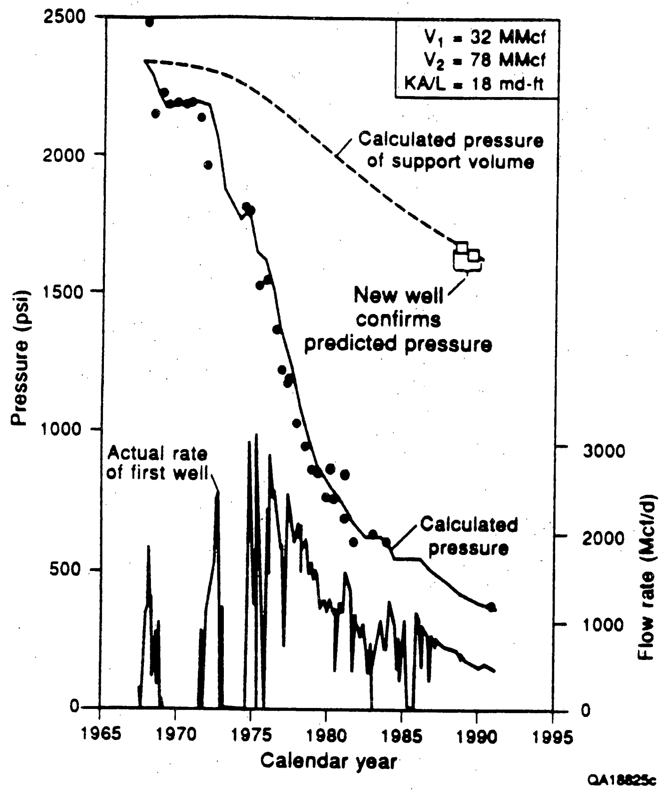

Figure 3. An Example Of A Pressure History Match Using The Personal Computer-Based Compartment Model Gas Reservoir Simulator. Solid Dots Are Actual Pressure Data; Open Squares Are Pressure Data From A New Well In The Supporting Compartment.

(VSP) images from within a 3-D seismic grid were critically integrated into the interpretation of the 3-D data volume. The major contribution of the VSP imagery was to identify the proper thin bed seismic responses which should be correlated with selected reservoirs. The 3-D seismic horizon time slices allow the identification and positioning of the various depositional facies including channel-fill, splays, and floodplain deposits (Figure 4). Areas of maximum seismic amplitude response outline the sinuosity of channel-fill deposits which could not be derived from well data alone, and therefore can significantly improve the capability for targeting depositionally controlled infield targets, especially in vertically stacked multi-reservoir fields. The 3-D data volume of seismic reflection amplitudes was converted into a 3-D volume of amplitude versus offset (AVO) responses, and a 3-D volume of rock impedance estimates. In addition, compressional or primary (P) and shear (S) wavefield separation of VSP data indicate that reflections from some gas reservoirs differ significantly. This vector wavefield approach to reservoir imaging may hold promise for determining which combination of P and S seismic attributes and which seismic-derived P and S parameters best image compartmented natural gas reservoirs.

FUTURE WORK

Three major areas of future work that remain under this project include:

- *Detailed analysis of Stratton field will combine geologic, engineering, geophysical, and petrophysical data to document reservoir heterogeneity and define flow units.*

  Stratton field has been the site of intensive engineering well testing to evaluate geologic interpretation; such testing will continue and geophysical data collection (3-D seismic and VSP) will be added to help verify reservoir geometry. All data collection is planned to be completed by August 31, 1992 and a five- to six-month documentation and technology transfer phase will follow.

- *Project documentation will accelerate and additional completed research results will be published.*

  Four topical reports have been completed and three are published. A topical report on dipmeter analysis at McAllen Ranch field documents the utilization of dipmeter logs to help identify internal reservoir heterogeneity. Topical reports on integrated studies of deltaic reservoirs (McAllen Ranch field), on integrated studies of fluvial reservoirs (Seeligson field), and on a compartmented reservoir simulator (G-Wiz model) are completed. Numerous papers are being given, many

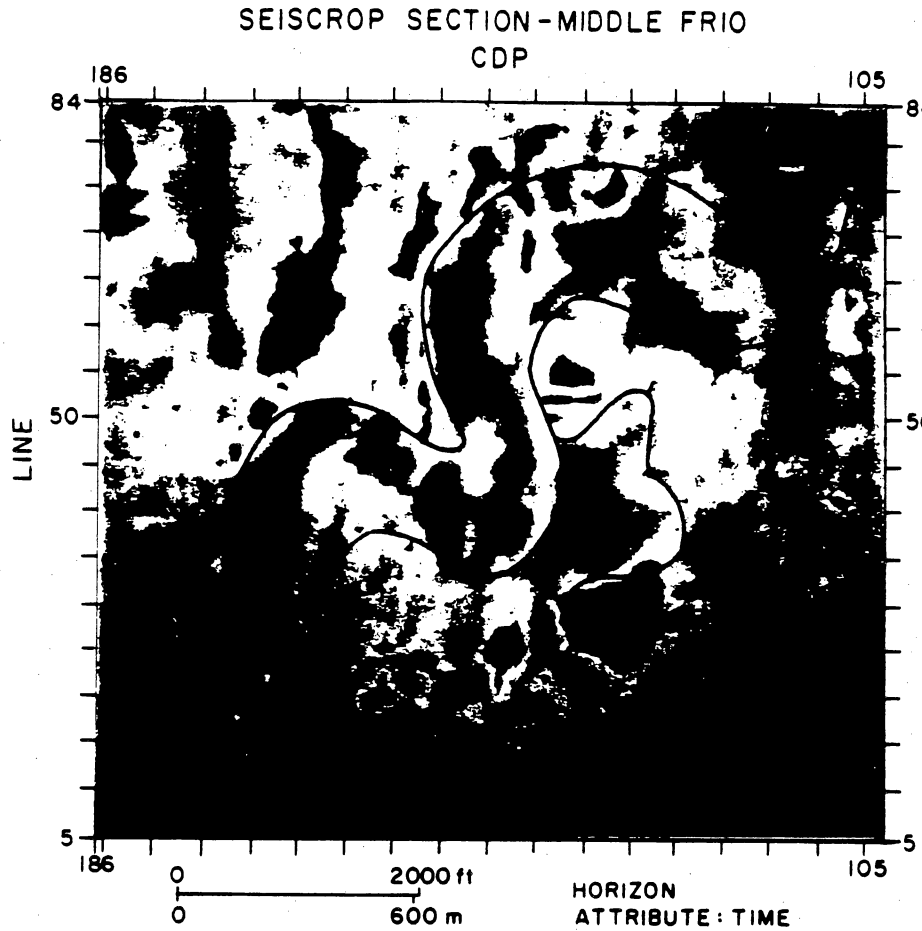

Figure 4. Three-Dimensional Horizon Slice Map Of Reflection Amplitude Showing The Sinuosity And Lateral Extent Within A Typical Middle Frio Fluvial Gas Reservoir, Seeligson Field, South Texas.

invited, and abstracts, articles, and other documentation is in preparation.

- *Concepts of how depositional and diagenetic reservoir heterogeneity control reserve growth opportunities will continue to be formalized and transferred to industry in a workshop format. Mini-evaluations will be set up to test SGR concept extrapolation.*

Three SGR technology transfer workshops (Levey and others, 1992) were held in Houston in late 1991 and early 1992 and all were completely sold out. Three more workshops are set for April and May, 1992, two of which are sold out. These 1992 workshops incorporate some new engineering data, but do not yet include Stratton geophysics delayed by South Texas flooding. A late Fall 1992 follow-up workshop and a new, full SGR workshop will include geophysics and outcrop analog (Ferron Sandstone; Tyler and others, 1991; Guevara and others, 1992)—subsurface (Lake Creek field) comparisons.

Short-term studies ("mini-evaluations") outside of current field areas will help evaluate SGR concepts and test extrapolation potential. So far, one mini-evaluation has been planned with full operator cooperation.

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Appendix D: 1993 DOE/METC Conference

Incremental Natural Gas Resources Through Infield Reserve Growth/Secondary Natural Gas Recovery

CONTRACT INFORMATION

Contract Number	DE-FG21-88MC25031
Contractor	Bureau of Economic Geology The University of Texas at Austin University Station, Box X Austin, Texas 78713 (512) 471-1534
Contractor Project Manager	Robert J. Finley
Principal Investigators	Robert J. Finley Raymond A. Levey Bob A. Hardage
METC Project Manager	Charles W. Byrer
Period of Performance	September 1, 1988 to April 30, 1995

Schedule and Milestones

FY93 Gulf Coast Program Schedule

	O N D J F M A M J J A S
Task 1.0 Methodology for Choosing Study Areas	
• Evaluation of Operator Activity	Completed
• Initial Simulator Configuration	Completed
• Initial Field Screening	Completed
• Refined Field Screening	Completed
Task 2.0 Untapped Compartments: Integrated Characterization of Candidate Reservoirs (Sandstones)	
• Geological Characterization	Completed
• Development of Cross Section Frameworks	Completed
• Mapping of Target Reservoirs	Completed
• Engineering Characterization	Completed
• Geophysical Characterization	Completed

O N D J F M A M J J A S

Task 3.0 Formation Evaluation for Bypassed Gas Zones
- Geological Support for Formation Evaluation ______________Completed ______________
- Sample Analysis for Shaly Sandstone Evaluation ______________Completed ______________

Task 4.0 Interwell Extrapolation and Related Deeper Pools
- Subregional Stratigraphic Analysis ______________Completed ______________
- Field-Scale Analysis of Deeper Play Components — No activity as advised by TAC

FY94 Midcontinent Program Schedule

O N D J F M A M J J A S

Task 1.0 Selection of Resource Targets and Depositional Settings Within the Midcontinent
- Evaluation of Suitable Plays and Resource Volumes __Completed
- Contact Operators to Determine Level of Activity and Interest __Underway
- Selection of Fields for Cooperative Studies — Site 1 selected
- Definition of Reservoir Targets __Underway

Task 2.0 Determination of Controls on Unrecovered Gas Resources
- Framework for Target Reservoir Characterization ___Underway
- Initial Reservoir Architecture Delineation ___Underway
- Integrate Geophysical Analysis, Engineering Assessments, and Well Log Analysis __Underway
- Define Cooperative Data Collection and Testing __Underway
- Integrate Results of Field Data Collection to Refine Reservoir Characterization — No activity scheduled

Task 3.0 Synthesis of Results and Development of Advanced Gas Recovery Strategies
- Establish Extent of Flow Unit(s) — No activity scheduled
- Define Flow Units Characteristics of Reservoirs — No activity scheduled
- Determination of Extrapolation Potential — No activity scheduled

Task 4.0 Technology Transfer
- Printed Reports and Presentations — No activity scheduled
- Workshops to Transfer Results to Operators ____*_______**____Underway
- Development of Advanced Technology Transfer Products __Underway
- Economic Analysis of Reserve Growth Strategies __Underway

* Houston **Proposed for San Antonio

OBJECTIVES

The primary objective of the Infield Reserve Growth/Secondary Natural Gas Recovery (SGR) project is to *develop, test, and verify technologies and methodologies with near- to midterm potential for maximizing the recovery of natural gas from conventional reservoirs in known fields*. Additional technical and technology transfer objectives of the SGR project include:

- To establish how depositional and diagenetic heterogeneities in reservoirs of conventional permeability cause reservoir compartmentalization and, hence, incomplete recovery of natural gas.

- To document examples of reserve growth occurrence and potential from fluvial and deltaic sandstones of the Texas gulf coast basin as a natural laboratory for developing concepts and testing applications to find secondary gas.

- To demonstrate how the integration of geology, reservoir engineering, geophysics, and well log analysis/petrophysics leads to strategic recompletion and well placement opportunities for reserve growth in mature fields.

- To transfer project results to a wide array of natural gas producers, not just as field case studies, but as conceptual models of how heterogeneities determine natural gas flow units and how to recognize the geologic and engineering clues that operators can use in a cost-effective manner to identify incremental, or secondary, gas.

The SGR project is a joint research effort of the Gas Research Institute (GRI), the U.S. Department of Energy (DOE), and the State of Texas conducted in cooperation with industry partners. Approaches to defining the distribution of unrecovered resources by depositional system and methods for maximizing their recovery are being developed and tested. The Gulf Coast research effort focused specifically on Texas natural gas reservoirs as a major subset of the Nation's natural gas resource base. The recently initiated SGR Midcontinent project is designed to test and expand the application and benefits of reserve appreciation concepts and technology in a second major natural gas province.

Results of the SGR project are enabling producers to economically recover this discovered but undeveloped natural gas resource through integrated geological, engineering, petrophysical, and geophysical assessments. Case studies conducted with the cooperation of independent producers have demonstrated the cost-benefit viability of an integrated SGR approach for small operators producing from gas reservoirs in similar and different depositional systems.

BACKGROUND STATEMENT

Between 1918 and 1975 half of the natural gas wells in the United States were drilled. The second half were drilled between 1976 and 1992 for a total of more than 410,000 wells. Almost 80,000 of these wells were drilled between 1981 and 1985. The per-completion gas recoveries have almost doubled since the first half of the 1980's. However, what producers found during the 1980's was that reservoirs were more complex internally than previously thought and that reservoir heterogeneity leads to compartmentalization that traps secondary (incremental) gas in many reservoirs that have been commercially producing from known fields.

In the late 1970's and 1980's, the characterization of the internal geometry of reservoirs, mainly oil reservoirs, clearly demonstrated a greater degree of compartmentalization than had been previously recognized. Factors affecting this compartmentalization include the depositional system of the reservoir, structural configuration, and diagenetic history of the reservoir following deposition. These lessons were first learned for oil reservoirs, but starting in the late 1980's became increasingly evident for gas reservoirs. The conceptual view of the resource base in the lower 48 states changed drastically from the middle and late 1970's when estimates by M. K. Hubbert of more than 90 percent depletion were revised based on more recent analyses indicating that the natural gas resource base is only about 40 percent depleted (Fisher, 1993). Strategies developed during this research are being used by producers and pipeline companies to target 236 Tcf of reserve growth potential. This potential constitutes part of the 1,295 Tcf of technically recoverable resources that the National Petroleum Council (NPC) identified as existing in the lower 48 states (NPC, 1992).

The SGR project focused on three major gas plays in the Frio and Vicksburg Formations and Wilcox Group that have produced more than 18 Tcf of natural gas in the Gulf Coast Basin. Using six fields (McAllen Ranch, Seeligson, Stratton, Lake Creek, Agua-Dulce, and North McFadden) (figure 1), the project has cooperated with a broad spectrum of gas operators including Shell Western E&P Inc., Mobil E&P Inc., Union Pacific Resources Corp., Oryx Energy Co., Pintas Creek Oil Co., and Anaqua Oil and Gas Inc. Non-geopressured, conventional permeability reservoirs like the middle Frio Formation (cumulative production >12 Tcf) were the primary emphasis in these SGR studies. These reservoirs were deposited as part of a bedload-rich fluvial system that fed a major deltaic depocenter in South Texas.

PROJECT DESCRIPTION

The reserve growth resource in a natural gas field will be contained in *new infield reservoirs*, *untapped or incompletely drained reservoir*

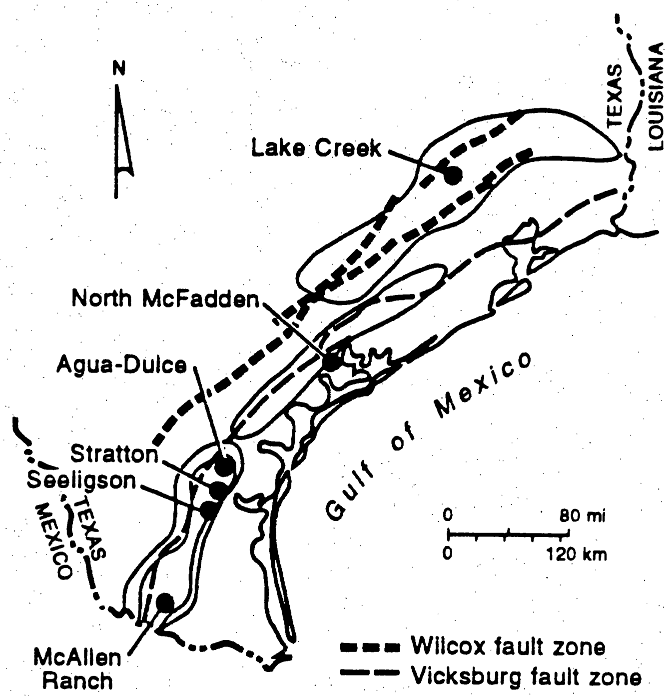

Figure 1. Location map of the fields and major gas plays investigated by the Secondary Gas Recovery (SGR) project in the Gulf Coast Basin.

compartments, *bypassed reservoirs*, and *deeper pool reservoirs* (figure 2). The latter have long been a recognized target for the producing industry, and for natural gas, deeper pool development benefits from the more gas-prone nature of deeper stratigraphic intervals. The SGR project's Technical Advisory Committee (TAC) determined that deeper pool reservoirs should not be a focus of the project because industry recognizes deeper pool reservoir potential and that the other more difficult to develop resources should be given priority.

New infield reservoirs are new reservoirs separated vertically and laterally from adjacent reservoirs that were not contacted during original development of the field. Often, these reservoirs are found during deeper-pool development attempts. *Untapped or incompletely drained reservoir compartments* are parts of established producing reservoirs that may or may not have been

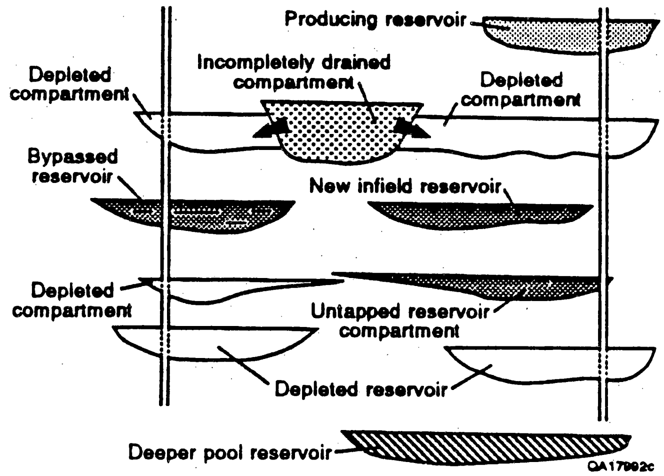

Figure 2. Diagrammatic sketch of reservoir compartment terminology used in the SGR project.

contacted during original development of the field and are not in flow communication, or are in incomplete flow communication, with existing completions. *Bypassed reservoirs* are reservoirs contacted by existing wells that have not been produced. Bypassed reservoirs may have been thought nonproductive or noneconomic based on previous well log evaluations. All of these types of reservoirs are targets for incremental natural gas recovery based on understanding of depositional and diagenetic heterogeneity that leads to reservoir compartmentalization. Although structural complexity also results in incomplete recovery, the focus of the SGR project has been to better understand depositional rather than structural reservoir variability.

RESULTS

Synopsis of Gulf Coast Basin Research

Results from this project provided strategies for evaluating infield development in fields that are from 30 to more than 50 years old (Finley and others, 1992). Significant natural gas reserve appreciation opportunities exist where reservoirs are heterogeneous and compartmentalized. Such compartmentalization, other than structural, is depositional and/or diagenetic in origin and can be defined through a geologically-centered approach to understanding reservoir flow units. Concept-driven integration of disciplines is crucial to recognizing and exploiting reserve growth opportunities. Although absolute rules on flow communication between different depositional facies are not apparent, smaller compartments often show evidence of baffles that affect reservoir flow units and can provide a significant incremental natural gas resource.

Several techniques exist for assessing the potential for secondary incremental gas recovery in a field, among a group of reservoirs, or within individual natural gas reservoirs. These techniques include the evaluation of geologic, engineering, and geophysical data at (1) the field-to-reservoir scale and (2) the reservoir-to-flow unit scale. Geological techniques include recognition of depositional and diagenetic facies in the field, determining the reservoir architecture stacking pattern, and identifying intrareservoir flow boundaries. Geophysical techniques include looking for variable seismic reflection response within the field and considering the thin-bed reflection amplitude behavior within a targeted reservoir horizon. Engineering clues can include identifying fields and reservoirs that are characterized by elevated completion or wireline pressure tests. Methods for detecting compartmented behavior in a reservoir include evaluating rate-time diagnostic plots for evidence of pressure support from a secondary volume to the primary volume produced by the well being analyzed.

Geologic strategies are often initially deterministic and include identifying which part of a field has reservoirs with the greatest depositional, diagenetic, and structural variability. Geophysical strategies include integrating vertical seismic profiles (VSP's) with 3-D seismic imaging for remotely mapping subsurface reservoir heterogeneity in the interwell space. The cost of 3-D seismic acquisition and processing continues to diminish and, depending on the size of the survey, surface conditions, and the nature of the target objectives, the acquisition cost of onshore surveys can be reduced to only a few tens of thousands of dollars per square mile. Engineering strategies include a newly developed PC-based compartment model simulator that was developed as part of the SGR project. Whereas geology and geophysics determine the shape and form of reservoir compartments, the simulator focuses on modeling reservoir function.

Deltaic Reservoir Characterization

Evaluation of heterogeneous deltaic gas reservoirs in the Wilcox Group at Lake Creek field indicates that a combination of capillarity and facies defines reserve appreciation opportunities. An SGR strategy of targeting distributary-channels in the developed and downdip flank areas could access 8.7 Bcf of incremental gas resources in a single operational reservoir (Grigsby and others, 1992). Most of this secondary gas resource is located downdip from existing development. Reservoir facies consist of delta-front, channel-mouth-bar, and distributary-channel sandstones (figure 3). A new advanced capillary pressure model (ADCAP) was employed to predict the downdip limits of gas production in the three reservoir facies. This ADCAP model relates the four important reservoir properties of porosity, water saturation, permeability, and capillary pressure with a single equation. The potential area containing the SGR resource is based on effective permeability to gas calculated from the mean value of air permeability for each reservoir facies and water saturation resulting from height above the free water level (figure 4).

Engineering evaluations of recovery and production performance indicate that the most effective development strategy involves targeting completions in the distributary-channel facies. Analysis of gas productivity by facies shows that distributary channel completions have 2.3 times the kh (14.1 versus 6.2 md-ft) and 3.9 times the EUR (2,265 versus 581 MMcf) of non-channel completions. The effective drainage areas for distributary channel completions were found to be 200 acres (or greater) compared to 40 acres for non-channel completions. Many Wilcox gas fields are characterized by multiple stacked gas deltaic packages. Each of these deltaic packages could also contain incremental gas resources. The integrated SGR methods and concepts of capillarity used in analysis of these deltaic reservoirs in Lake Creek field are transportable and should help identify additional gas resources in other heterogeneous gas fields with low- to conventional-permeability reservoirs.

Fluvial Reservoir Characterization and Stochastic Modeling

The Gas-Wizard (G-WIZ) PC-based compartmented gas reservoir simulator (figure 5), developed by the SGR project as a reservoir management tool (Lord and Collins, 1991; Collins and Lord, 1992) was applied to a set of reservoir compartment realizations modeled under different development timing and completion spacing scenarios. Three classes characterized by large, medium, or small reservoir compartment sizes were delineated from 10 groups of Frio reservoirs stacked over a 2,000 ft interval in Stratton-Agua Dulce field (figure 6a). Producing rate and static pressure data were used to determine the three fundamental reservoir parameters: primary drained pore volume, supporting pore volume, and barrier transmissibility. Statistical distributions of the primary pore volume and transmissibility were found to be closely approximated by a log-normal distribution in each of the 10 reservoir groups (figure 6b). Forward stochastic modeling of gas recovery from the three compartment size

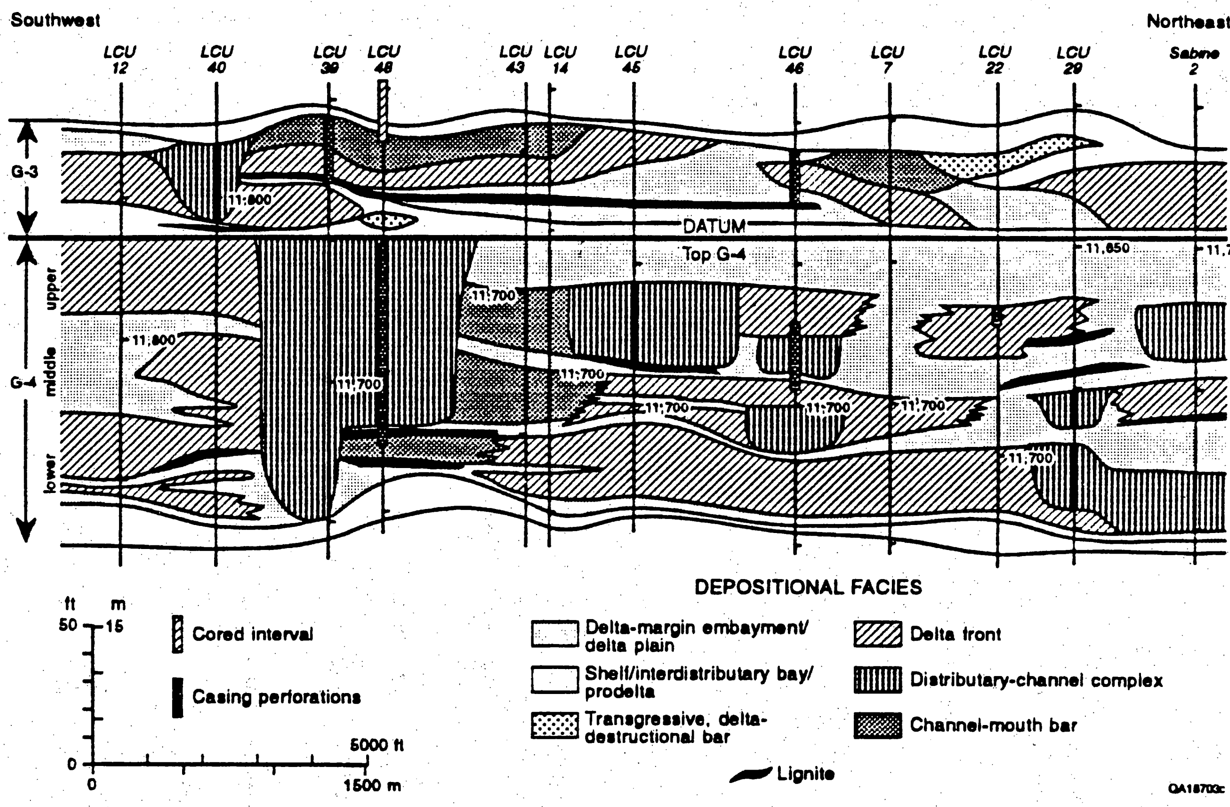

Figure 3. Depositional strike oriented stratigraphic cross section showing reservoir units and heterogeneity in Lower Wilcox Group deltaic reservoirs.

classes indicates that well spacings of 340, 200, and 60 acres (or less), respectively provides maximum gas contact efficiency (figure 6c). Building a stochastic modeling process with data and output from the G-WIZ simulator defined an approach to understanding effective well spacing in different classes of reservoir compartment size distributions.

The stochastic technique generates realizations of fluvial reservoirs having internal compartments with intervening barriers. Simulations of multiple reservoir realizations honoring statistical distributions determined from reservoir data yield a unique probability distribution of expected gas recovery. Recovery factors were evaluated for different well spacing and completion timing scenarios. By this method, statistical predictions of recovery are generated for each of the three classes representing a spectrum of fluvial reservoirs. For example, in the small compartment size class, incremental recovery potential of 24 percent is predicted by decreasing completion spacing from 320 to 160 acres (figure 7). The correlations developed should be transferable to other fields with similar fluvial facies architecture.

Reservoir Geophysics

Analysis of 3-D seismic imagery in a 7.5 mi^2 grid, coincident with multiple well tests in Stratton field, was used to investigate reservoir compartment boundaries identified by other SGR techniques. Flattening and seiscrop slicing above and below reference horizons were used to reveal depositional topography and to determine the extent of structural influence on reservoir horizons. Seismic time-to-depth calibration of seismic

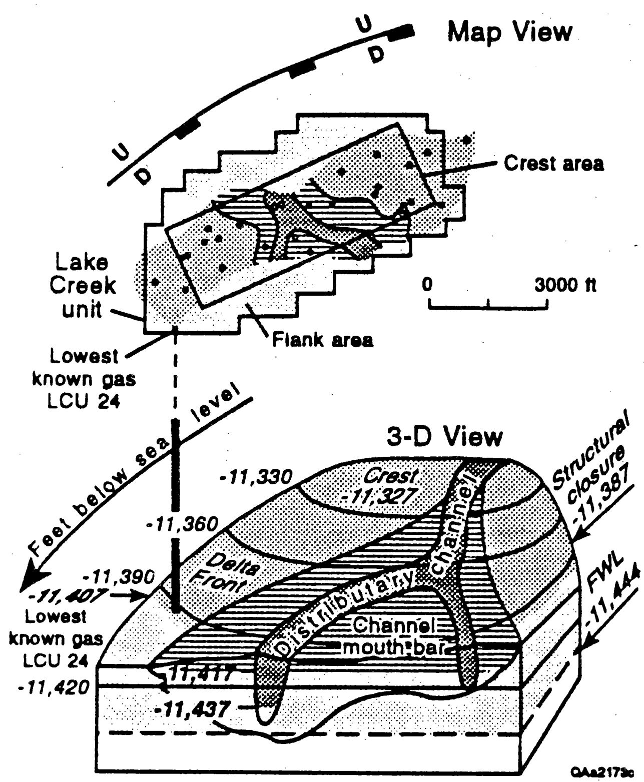

Figure 4. Reservoir model showing capillary control of incremental gas resources by depositional facies.

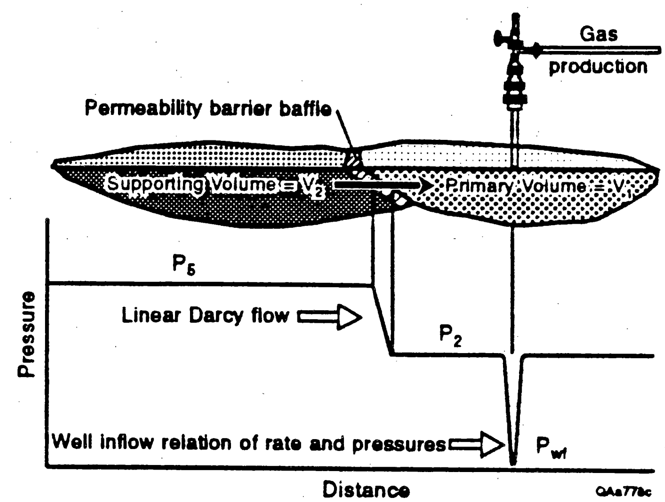

Figure 5. Compartment model (used in G-Wiz gas compartmented reservoir simulator) that describes heterogeneous reservoir function as a set of tank-like compartments having leaky barriers that separate compartments from wells that produce from these compartments.

thin-bed intervals was achieved by careful attention to detail during 3-D data acquisition and processing and by using high quality zero-offset VSP data to define exactly where thin bed time windows exist in the surface-recorded seismic responses. Many Stratton reservoirs are only 10 to 15 ft thick, and occur within seismic time windows as thin as 2 to 4 ms at depths as deep as 6,700 ft. Careful calibration is required to accurately locate these time windows in the reflection waveforms.

In many reservoirs, the depositional topology revealed in these thin bed seismic images clearly indicates where a compartment boundary should be positioned between well control and the reservoir compartment boundaries are imaged within, or adjacent to these channels (figure 8 a, b, c). At other reservoir levels where either geologic or engineering data indicate a compartment boundary, the boundary is not obvious in the seismically-revealed depositional topography. In these latter instances, the seismic image usually shows a semi-continuous depositional unit, which implies this second type of compartment boundary does not significantly affect the reflected seismic wavefield. Although many subtle, fluvially deposited compartment boundaries are revealed in these 3-D seismic images, some boundaries cannot be seismically imaged due to minimal differences in the acoustic impedance of reservoir and non-reservoir facies and must be located by stratigraphically correlating geologic data, analyzing production histories, or performing well pressure tests. In all cases, the interpretation of 3-D images at 10 reservoir levels provided more information about the distribution of reservoir facies in the interwell spaces than could be obtained by only extrapolating geologic and engineering data from control wells. 3-D seismic provides a highly effective tool for imag-

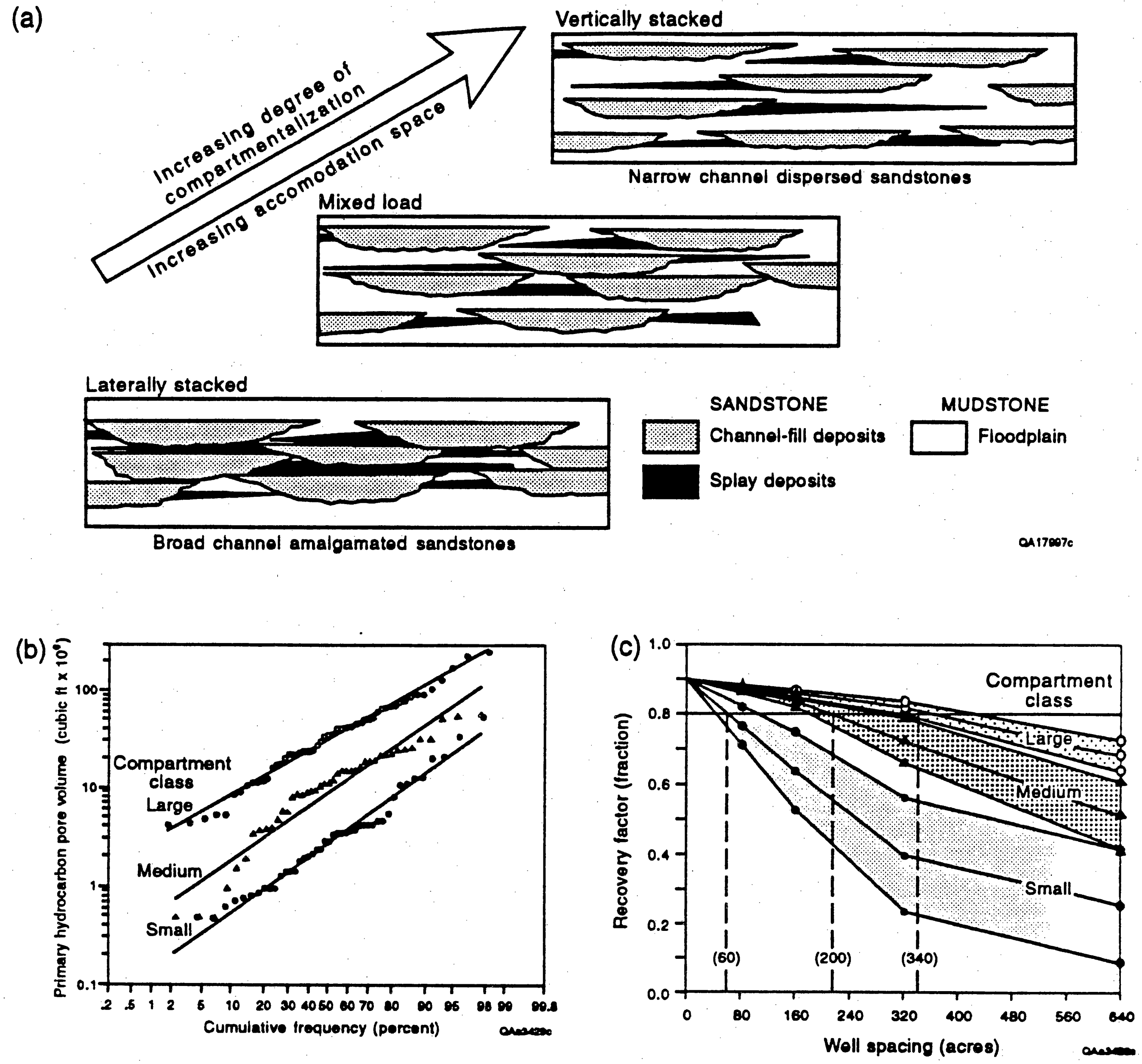

Figure 6. (a) Schematic diagram illustrating the fluvial architectural continuum of large, medium, and small size reservoir compartments, (b) cumulative frequency distribution of primary pore volume for the three reservoir compartment size classes, (c) recovery factor and predicted gas recoveries versus well spacing for large, medium, and small compartment size classes.

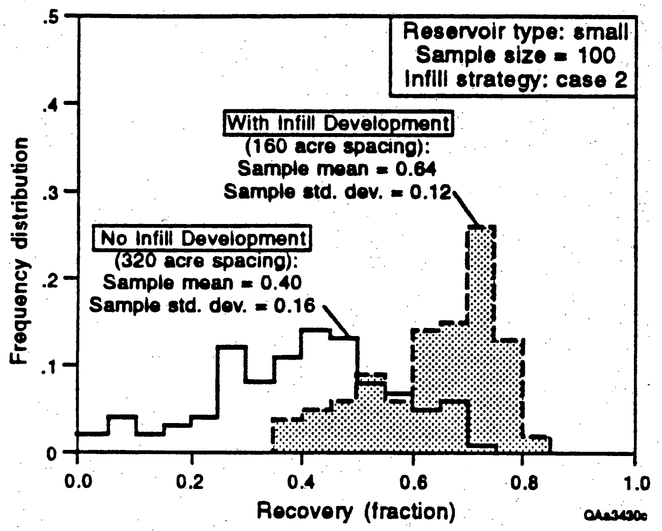

Figure 7. Frequency distribution illustrating effect of completion spacing on incremental gas recovery for the small compartment size class.

ing interwell space, even when targeting relatively thin reservoirs.

Case Histories (Mini-evaluations)

The SGR project, in cooperation with operator-initiated redevelopment in two fields that are over 50 years old, evaluated the application and benefit of SGR concepts and technologies (Levey and others, 1993b). Integrated geologic, engineering, and petrophysical analysis of 21 reservoirs defined original gas in place (OGIP) of 37 Bcf, of which 28 Bcf is technically recoverable. Economically recoverable gas reserves were estimated at 10 Bcf in two study areas totaling 2,300 acres. The reservoirs are normally pressured, primarily depletion-drive reservoirs, at moderate depths between 3,700 and 7,000 ft.

In case I, secondary gas resources occur in thin-bedded shoreface deposits. By using the state-of-the-art induction array tool, thin-bed high productivity reservoirs can be better identified than by using conventional electrical and induction logs. Detailed stratigraphic analysis of multiple thin-bed intervals in combination with resistivity cutoffs and spontaneous potential ratios provided a means of identifying locations for enhancing the operator's ability to recover these secondary gas resources. In case II, secondary resources were defined in fluvial depositional reservoir facies segmented by structural compartments and affected by stratigraphic variability and diagenesis. Integrated formation evaluation using high resolution logging, spectral gamma ray measurements, wireline pressure tests and core analysis were effective in identifying additional gas resources.

For cases I and II, the average ultimate recovery is 400 and 260 MMcf per completion, respectively. The total cost to develop and produce SGR reserves is projected at $0.58 (case I) and $0.83 (case II) per mcf (exclusive of royalties). The primary difference between the two case studies is that the case II area has smaller reservoir compartments caused by faulting and depositional and diagenetic effects on reservoir productivity. As a consequence of smaller compartment size, development costs are higher due to the requirement of more wells and recompletions to access the SGR resource. These mini-evaluations demonstrate the feasibility of using SGR approaches for converting technically recoverable resources into economically producible reserves at low to moderate cost.

Technology Transfer

Technology transfer to the gas industry has included more than 30 research presentations at international, national, and regional meetings and technical publications in 1992 and 1993. Invited SGR technical presentations that were made by project staff were co-sponsored by geologic, geophysical, and petrophysical groups especially interested in gas research directed at reserve appreciation.

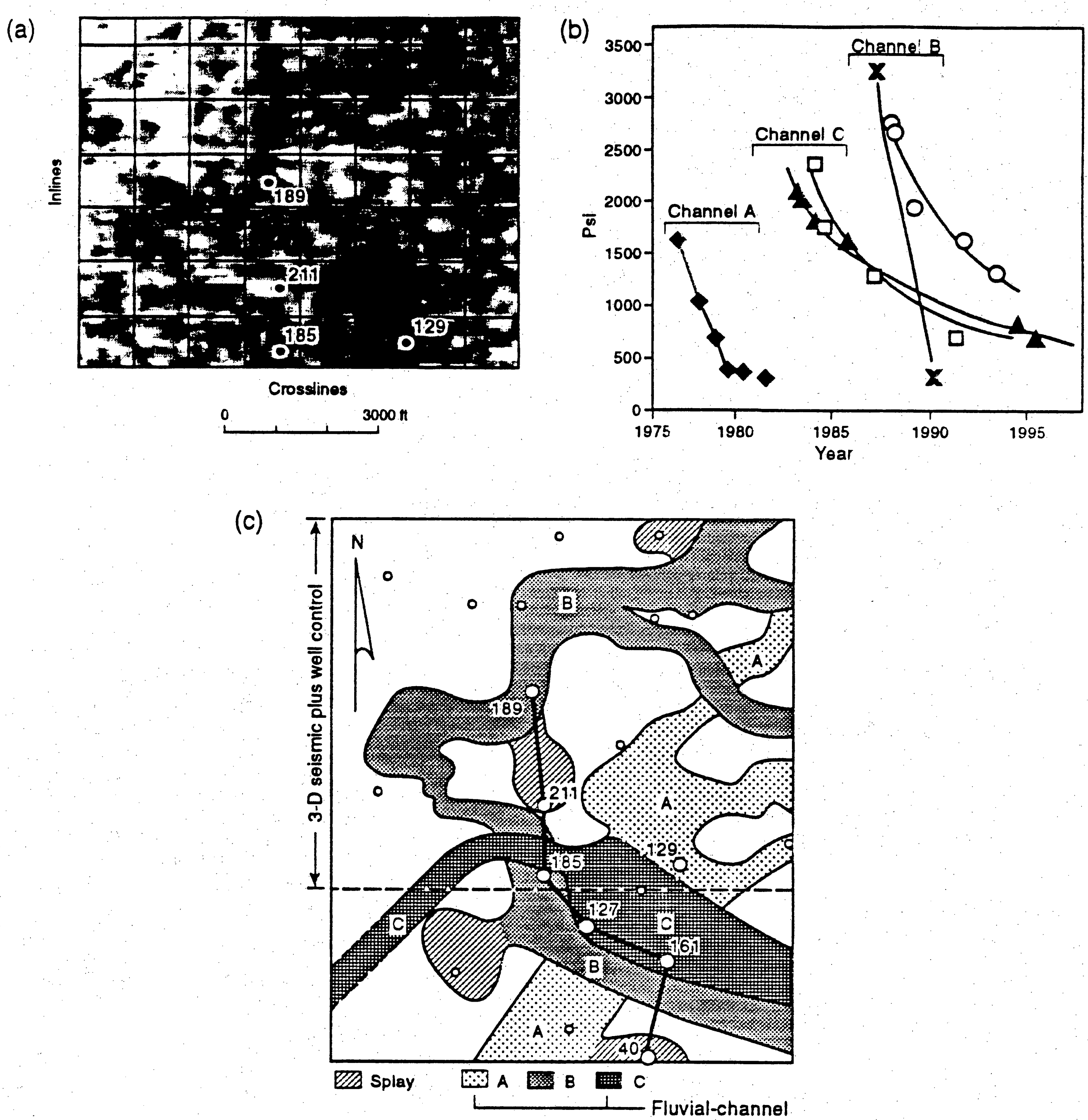

Figure 8. (a) 3-D seismic reflection amplitude image showing the position of three highly sinuous fluvial-channel and splay systems, (b) pressure history used to detect three fluvial reservoir compartments (c) integrated geophysical, geological, and engineering reservoir model showing three vertically stacked channel systems.

Beyond comprehensive written documentation contained in 7 technical reports of project results from the Gulf Coast research program (Ambrose and others, 1992; Collins and Lord, 1992; Grigsby and others, 1992; Langford and others 1992a, 1992b; Levey and others, 1993a, 1993b), short courses were conducted in three states (Texas, Oklahoma, and Louisiana) in the cities of Houston, Corpus Christi, Midland, San Antonio, Oklahoma City, and New Orleans. Over 700 people participated in full-day short courses and half-day presentations included in gas reserve growth technology workshops sponsored by the Texas Independent Producers and Royalty Owners in Austin, Dallas, Amarillo, and Houston. Participants from production, exploration, and pipeline companies attended these short courses presented by the SGR project staff on behalf of DOE and GRI and co-sponsored by national and regional technical societies. Sixty-eight percent of the short course survey participants indicated that they will make direct application of the materials presented to their gas reservoir development and 98 percent believe research of this nature is valuable. Additional short courses are now scheduled for November 1993 in Houston and February 1994 in San Antonio. A development plan for advanced technology products is now under consideration and may include a project video, a how-to manual for step-by-step reservoir evaluation by field operators, a CD-ROM containing project topical reports, and revised short courses that expand the use of 3-D geophysics for maximizing recovery in compartmented gas reservoirs. These products will help operators evaluate their own properties and implement low-cost reserve appreciation strategies.

FUTURE WORK

Technical Issues in Midcontinent Sandstone Reserve Growth

In contrast to fluvial deposits, many deltaic deposits have a cyclic component that should allow predictable quantification of the stratigraphic reservoir framework from standard well log control. Recent advances in sequence stratigraphic concepts to define reservoir architecture are more commonly applied in an exploration mode in contrast to an exploitation, or reservoir development, phase. Few gas operators outside of the majors have used this approach to resource evaluation in real, field-scale operations. However, reservoir flow units defined through this predictive stratigraphic approach should be measured and compared to known production to assess the degree of compartmentalization. The cratonic basins of the Midcontinent are an appropriate area to develop this approach. Confirmation of reservoir discontinuity by geophysical techniques will help operators identify those gas fields with the greatest potential for resource appreciation.

Deltaic depositional systems are characterized by gradational lithologic and facies changes that often provide only subtle discontinuities at sequence boundaries. Differences in subsidence rates between cratonic basins with supporting carbonate shelves, such as in the Midcontinent and the Gulf Coast Basin, will further affect reservoir architecture. Understanding the relationship between seismic resolution and these subtle changes in reservoir heterogeneity in transitional rock types is critical to establishing the limits of geophysical imaging using a diverse suite of techniques. In particular, cross borehole imaging techniques may be applicable to defining delta front, mouth bar, and distributary channel geometries in such Midcontinent settings.

Applications of this research are now being expanded and tested in the Midcontinent region of Oklahoma and Texas. More emphasis will be placed on deltaic facies in contrast to the fluvial facies of Seeligson and Stratton fields in the Gulf Coast program. Different subsidence rates prevailed in Midcontinent cratonic basins and some reservoirs will be closer to their source areas, affecting both reservoir geometry and quality. Increased emphasis is expected on geophysical technologies to establish a better balance with geology, engineering, and formation evaluation. Follow-up work on capturing technology transfer potential from the Gulf Coast effort will be used early in the Midcontinent program.

The Midcontinent region contains 33 to 41 Tcf of reserve growth resources at less than 15,000 ft—the largest volume after the onshore Gulf Coast Basin resource. The project will now focus on Pennsylvanian sandstone reservoirs in the Midcontinent region which contains 15 gas plays in Pennsylvanian-age sandstones (Bebout and others, 1993), suitable for extrapolation of the Gulf Coast results. Field study sites in the Midcontinent of Oklahoma and Texas will be selected to investigate the distribution of unrecovered resources, develop advanced recovery strategies, enhance geophysical applications in reserve appreciation, promote advanced technology transfer, and perform economic analysis of reserve growth strategies.

Midcontinent operators have actively sought participation in the SGR program and the first Midcontinent study site is in the Fort Worth Basin in North-Central Texas. The SGR project is actively involved with three companies (OXY USA Inc., Midland; Enserch Operating Partnership, Dallas; and Threshold Development Corporation, Fort Worth). The study site is the Boonsville field. Boonsville was discovered in 1945, had produced 53 Bcf in 1990 (ranked 32nd in the U.S.), and ranks 27th nationally in cumulative production. Operator cooperation and cofunding is highly leveraged (more than 10:1 operator-to-project funds) with all three operators agreeing to jointly acquire 3-D surface seismic comprising approximately 25 mi^2 in parts of Jack and Wise counties. This 3-D survey, costing about $1.2 million dollars, will be one of the most extensive surveys ever conducted in the Fort Worth Basin. Two project cooperative wells have already been evaluated and a third well is planned before the end of 1993. Cooperative data gathering has included extensive whole coring of Atoka productive intervals, a zero-offset vertical seismic profile, and a vertical wave test to evaluate the potential for seismic thin-bed resolution which has allowed optimum pre-seismic acquisition design parameters to be implemented.

The SGR Midcontinent project, in cooperation with the Oklahoma Geological Survey at the University of Oklahoma in Norman, is actively pursuing the search for the second study site in Pennsylvanian deltaic sandstones in Oklahoma. Initial contacts and discussions with Oklahoma gas operators are underway to identify the appropriate site.

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