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INCREASING DEVELOPMENT EFFICIENCY IN LOW-PERMEABILITY GAS RESERVOIRS: A SYNOPSIS OF TIGHT GAS SANDS PROJECT RESEARCH

TOPICAL REPORT

(November 1982–December 1992)

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To enhance the application of research results by industry, this report provides a guide to the literature developed at the Bureau of Economic Geology in the Geological Analysis of Primary and Secondary Tight Gas Sands Objectives Project as part of the Gas Research Institute(GRI) Tight Gas Sands Research Program during the period 1982 through 1992. We review some of the key findings of the geologic studies published in 17 GRI topical reports and more than 90 Bureau of Economic Geology monographs, refereed journal papers, contributions to other GRI reports, and papers and abstracts in meeting transaction volumes. This report is intended to be a directory to this literature.

The completion of the national survey *Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States* was an appropriate point to summarize and compile a guide to research results that cover a broad range of regions, formations, and geological and engineering topics, and that have been published in both geological and engineering journals, as well as GRI topical reports. This report is intended to be a companion to the *Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States,* which brings together geologic, reservoir characterization, and engineering insights on 24 producing low-permeability sandstone formations in 13 basins.

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RESEARCH SUMMARY

Title	Increasing development efficiency in low-permeability gas reservoirs: a synopsis of tight gas sands project research
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Principal Investigator	S. E. Laubach
Report Period	November 1982–December 1992 Topical Report
Objectives	To enhance the application of research results by industry, this report provides a guide to the literature developed at the Bureau of Economic Geology in the Geological Analysis of Primary and Secondary Tight Gas Sands Objectives Project as part of the Gas Research Institute (GRI) Tight Gas Sands Research Program in the period 1982–1992.
Technical Perspective	Since 1982, the Gas Research Institute (GRI) Tight Gas Sands Program has supported geological investigations designed to develop the knowledge necessary to produce gas from low-permeability sandstones efficiently. As part of that program, the Bureau of Economic Geology has conducted in-depth research on low-permeability sandstone in the Lower Cretaceous Travis Peak and Jurassic Cotton Valley formations of East Texas, the Upper Cretaceous Corcoran and Cozzette sandstones of Colorado, the Upper Cretaceous Frontier Formation of Wyoming, the Pennsylvanian Sonora Canyon Sandstone and Davis Sandstone of Texas, and the Pennsylvanian Cleveland Formation of Texas and Oklahoma, as well as conducting limited studies of other low-permeability sandstones and compiling two major national summaries of low-permeability sandstone reservoir attributes. This effort was part of a broader program designed to increase the understanding and ultimate utilization of gas resources in low-permeability formations through integration of geology, formation evaluation, reservoir engineering and fracture modeling. To develop advanced technologies verified in the field, which are necesary for continued cost-competitive production from low-permeability reservoirs is the objective of the GRI Tight Gas Sands Research Program.
Results	The completion of the national survey *Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States* is an appropriate point to compile a guide to research results that cover a broad range of regions, formations, and geological and engineering topics, and that have been published in both geological and engineering journals, as well as GRI topical reports. This report is intended to be a companion to the *Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States*, which brings together geologic, reservoir characterization, and engineering insights on 24 producing low-permeability sandstone formations in 13 basins. This report can serve as a directory to this literature.

Technical Approach

We review some of the key findings of the geologic studies published in 17 GRI topical reports and more than 95 Bureau of Economic Geology monographs, refereed journal papers, contributions to other GRI reports, and papers and abstracts in meeting transaction volumes.

Project Implications

The importance of detailed resource characterizations in low-permeability gas sandstone formations has been realized for many years by GRI. Through GRI-funded research, the understanding of the geologic processes affecting the source, distribution, and recovery of gas from these reservoirs has been greatly enhanced. This report and the companion atlas volume serve as references that will aid low-permeability gas sand development.

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OBJECTIVE OF THIS REPORT

This report provides a guide to the literature developed at the Bureau of Economic Geology in the Geological Analysis of Primary and Secondary Tight Gas Sands Objectives Project as part of the Gas Research Institute (GRI) Tight Gas Sands Research Program during the period 1982 through 1992. We review some of the key findings of the geologic studies published in 17 GRI topical reports and more than 95 Bureau of Economic Geology monographs, refereed journal papers, contributions to other GRI reports, and papers and abstracts in meeting transaction volumes. This report is intended to be a directory to this literature and to enhance the application of research results by industry.

The completion of the national survey *Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States* in December 1992 was an appropriate point to summarize and compile a guide to research results that cover a broad range of regions, formations, and geologic and engineering topics, and that have been published in both geologic and engineering journals, as well as GRI topical reports. This report is intended to be a companion to the *Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States*, which brings together geologic, reservoir characterization, and engineering insights on 24 producing low-permeability sandstone formations in 13 basins (fig. 1).

The first section, *Evolution of Geologic Investigations,* traces the history of the project and explains how the various formations became objects of our investigation. In the following section, *Research Approaches*, we summarize some of the main elements of reservoir characterization and geological analysis that are incorporated into many of the reports developed in this project. This summary section could not be comprehensive without repeating the reports themselves, so it should be regarded as a broad overview of methods rather than a complete listing of topics. In the *Synopsis of Research Results* an outline is presented of the main findings of Bureau geologic research on the Travis Peak, Frontier, Canyon, and Cleveland Formations, as is a summary of results from the recently completed national survey of 24 low-

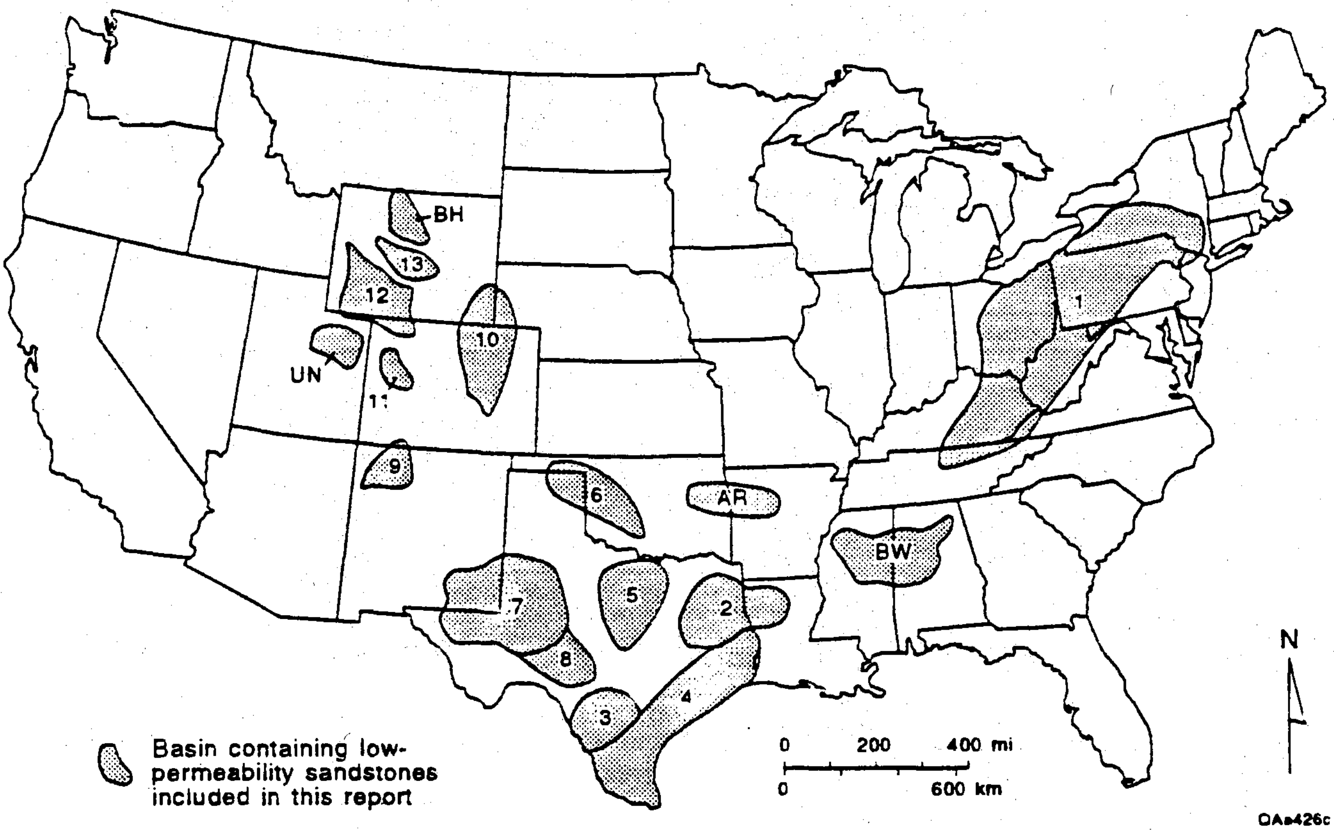

Figure 1. Map showing basins containing low-permeability sandstone gas reservoir formations described in the *Atlas of Major Low-Permeability Gas Reservoirs in the Continental United States* [23]. Labels on the map correspond to basin designations as follows: 1, Appalachian Basin; 2, East Texas Basin; 3, Maverick Basin; 4, Gulf Basin; 5, Fort Worth Basin; 6, Anadarko Basin; 7, Permian Basin; 8, Val Verde Basin; 9, San Juan Basin; 10, Denver Basin; 11, Piceance Basin; 12, Greater Green River Basin; 13, Wind River Basin; BW, Black Warrior Basin; AR, Arkoma Basin; UN, Uinta; BH, Big Horn Basin.

permeability reservoirs. In the sections *Review of Technology Transfer Success* and *Impact of Geological Studies on Efficient Gas Production* we briefly describe two measures of the dissemination and influence of this research on industry and the geological and engineering community at large. The final section, *An Annotated Summary of Project Publications*, is a list of the major topical reports and monographs, with brief summaries of their contents, and a list of other publications that stem directly from the project.

EVOLUTION OF GEOLOGIC INVESTIGATIONS

Since 1982 the Gas Research Institute (GRI) Tight Gas Sands Program has supported geological investigations designed to develop the knowledge necessary to produce gas from low-permeability sandstones efficiently. As part of that program, the Bureau of Economic Geology has conducted in-depth research on low-permeability sandstone in the Lower Cretaceous Travis Peak and Jurassic Cotton Valley Formations of East Texas, the Upper Cretaceous Corcoran and Cozzette sandstones of Colorado, the Upper Cretaceous Frontier Formation of Wyoming, the Pennsylvanian Sonora Canyon and Davis Sandstones of Texas, and the Pennsylvanian Cleveland Formation of Texas and Oklahoma, as well as conducting limited studies of other low-permeability sandstones and compiling two major national summaries of low-permeability sandstone reservoir attributes. This effort was part of a broader program designed to increase the understanding and ultimate utilization of gas resources in low-permeability formations through integration of geology, formation evaluation, reservoir engineering, and fracture modeling. To develop advanced technologies and understanding of the formations studied in depth and apply them to these and other formations to enable greater recovery of gas in place in low-permeability reservoirs is the goal of the GRI Tight Gas Sands Research Program.

Geologic analysis of low-permeability sandstones by the Bureau of Economic Geology began in 1982 with a national assessment of low-permeability reservoirs suitable for an extensive research program [28].* The next phase of study involved detailed evaluation of six tight gas sandstones and the selection of two of these units for comprehensive geologic, engineering, and petrophysical assessment: the Lower Cretaceous Travis Peak (Hosston) Formation in East Texas and northern Louisiana and the Upper Cretaceous Corcoran and Cozzette Sandstone Members of the Price River Formation (Mesaverde Group) in the Piceance Basin of Colorado. Because of limited development of the Corcoran and Cozzette at that time, detailed study of the genetic stratigraphy focused on three contiguous fields that contained most of the Corcoran–Cozzette production. In contrast, evaluation of the Travis Peak emphasized the establishment of a basinwide stratigraphic and structural framework across East Texas and North Louisiana.

In the subsequent phase of study, which required operator activity and cooperation, core and production data were collected extensively from cooperative wells drilled in the Travis Peak Formation. A total of 1,280 ft of Travis Peak core was drilled by GRI in seven cooperative wells, from which operating companies allowed GRI contractors to collect data, and an additional 1,440 ft of existing core was loaned or donated by operators. Research on the Corcoran and Cozzette Sandstones received lower priority during this phase of the project because operator activity in the Piceance Basin declined as a result of market conditions. However, one cooperative well was drilled through the Corcoran–Cozzette Sandstones to the underlying Sego Sandstone, and a total of 270 ft of core was recovered [59].

The first phase of geologic, engineering, and petrophysical assessment of the Travis Peak lasted from 1983 through 1986. Information gained from the cooperative wells, combined with detailed characterization of two regionally productive trends, or fairways, within the Travis Peak study area, led to drilling by GRI of three Staged Field Experiment (SFE) wells in the second phase of the Travis Peak study. The SFE wells were drilled and completed by GRI specifically for research on low-permeability gas reservoirs. SFE No. 1 was drilled in Waskom field Harrison County, Texas, in August 1986 [11], and SFE No. 2 was drilled in North Appleby field in

* Bracketed numerals refer to the annotated project-publication list at the back of this report.

September 1987 [12]. Research on these two wells focused on productive sandstones near the top and base of the Travis Peak Formation. Research on SFE No. 3, drilled in September 1988 in Waskom field, focused on the low-permeability Taylor Sandstone in the lower Cotton Valley Formation [13]. The purpose of drilling this well was to test the transfer of technologies, techniques, and models developed during study of the Travis Peak Formation to another formation, the Cotton Valley, that has a similar stratigraphic and tectonic setting. A total of 1,050 ft of core was taken from the three SFE wells.

The next phase of the project was to extend and apply, in a new area, techniques for the geological, geophysical, and engineering characterization of low-permeability reservoirs that were developed during work on SFE wells 1 through 3. This work would eventually involve drilling several cooperative wells and the SFE No. 4 well in a formation and basin having a set of geologic and engineering attributes substantially different from the Lower Cretaceous formations of East Texas. Part of the motivation for selecting another basin was that geologic variability has a vital effect on the success of engineering assessments and operations, and that in order to be robust, technical engineering solutions require testing in contrasting geologic settings. The process of selecting a site for SFE No. 4 began with an appraisal of 183 low-permeability formations in all major low-permeability gas producing areas across the country. From a group of four candidate formations that were reviewed in detail by the Bureau [22], the Upper Cretaceous Frontier Formation in the Green River Basin of southwestern Wyoming was selected as the site of SFE No. 4 on the basis of the scientific challenges and lessons that it provided, high incremental resource potential, and strong operator activity.

Information gained from three successful Frontier cooperative wells (including 520 ft of core), combined with geologic characterization of the Frontier throughout a study area that encompassed the area of greatest operator activity, led to GRI's drilling of SFE No. 4 in 1990 [15]. Specifically targeted was the Second Bench of the Second Frontier, which extends the length of the Moxa Arch and contains the most prolific Frontier gas reservoirs in the western

Green River Basin. The SFE No. 4 well was drilled in Chimney Butte field, Sublette County, through the Frontier Formation to a depth of 8,100 ft. A total of 323 ft of core was recovered.

Research was extended in 1990 to include the Pennsylvanian Canyon Sandstone in southwest Texas, where the efficiency of burgeoning operator activity was being impeded by lack of information on regional and reservoir geology. Regional geology of the Canyon was investigated in a five-county (Schleicher, Sutton, Edwards, Val Verde, and Crockett) study area in the Val Verde Basin and Ozona Arch—mapping of structure and sandstone geometry, construction of detailed stratigraphic cross sections, and description and interpretation of core from Sawyer and Sonora fields in Sutton County [32] and [61].

The Pennsylvanian Cleveland Formation had been considered as a candidate for the SFE No. 4 well [23] and, due to continued operator interest in geologic framework studies, a stratigraphic study of the formation was undertaken in a seven-county (Hansford, Ochiltree, Lipscomb, Hutchinson, Roberts, Hemphill, and Wheeler) area of the Anadarko Basin. Mapping of structure, formation thickness, and sandstone thickness was used to delineate reservoir distribution of this progradational clastic system, interpret depositional history, and characterize component facies [19].

In 1990 a screening process was initiated for choosing an appropriate low-permeability formation for the proposed GRI hydraulic fracture test site facility. A national screening of low-permeability formations was conducted by the Bureau to identify units that met the criteria for the test site. In the course of this work data from cooperative wells and a GRI research well were collected and analyzed [52].

By 1991, simultaneous studies were under way in the Frontier, Canyon, Davis, and Cleveland sandstones, and limited studies or reviews of other formations were in progress in support of proposed engineering experiments. These wide-ranging studies, together with previous work on the Travis Peak, Corcoran–Cozzette, and Cotton Valley set the stage for preparing a national survey of the depositional history, reservoir distribution, diagenesis, structure, in situ stress, engineering attributes, and production of 24 leading low-permeability sandstone reservoirs. The *Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States* (1993) resulted.

RESEARCH APPROACHES

A multidisciplinary approach to formation evaluation is the most accurate for assessing reservoir properties. This section, excerpted partly from the introduction to the *Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States*, summarizes some of the elements that have been found to be critical in characterizing low-permeability sandstone reservoirs.

Our geologic studies can be divided into (1) stratigraphy and depositional systems, (2) reservoir composition and diagenesis, and (3) structural history, structural geometry, natural fractures, and stress attributes. Information on each of these topics is necessary to completely characterize any tight formation geologically. Stratigraphic information explains the physical framework in which the gas resource exists. Depositional history determines the regional distribution, geometry, and texture of the reservoir sandstones, as well as the characteristics of the nonreservoir facies that may act as barriers to vertical growth of hydraulic fractures resulting from high in situ stress. Production characteristics of tight gas reservoirs are partly controlled by diagenetic modifications to the reservoirs; extensive cementation is commonly why permeability is low. Finally, studies of structural history and geometry, natural fractures, and stress attributes are important to the understanding of tight gas resources because hydraulic fracture treatments are commonly carried out to achieve economic flow rates. Horizontal drilling is a promising method for developing low-permeability gas reservoirs. Determining the present stress state in reservoir rocks and adjacent strata helps the direction of hydraulic fracture propagation to be predicted and fractures to be contained more effectively. In addition to potentially providing conduits for fluid flow to the wellbore, the abundance and orientation of natural fractures may affect the orientation and shape of hydraulic fractures and influence fluid leakoff characteristics.

Stratigraphy and Depositional Systems

A *depositional system* is a group of lithogenetic facies linked by depositional environment and associated processes. In other words, it is a group of rock strata that were deposited in closely associated sedimentary environments. Depositional systems are the stratigraphic equivalent of major physical geomorphic units, such as modern rivers or deltas. The depositional system can be divided into its component genetic *facies*, which are three-dimensional rock bodies characterized by specific sand-body geometries, lithologies, sedimentary structures, and initial porosity and permeability. Understanding at the facies level is a goal of stratigraphic analysis because commonly at the facies scale the basin's fluid migration pathways, including those of gases and connate waters, are established. A particular facies will have similar characteristics no matter where it has been deposited as long as energy conditions, processes, available sediment supply, and accommodation space were relatively uniform. Thus, classifying tight gas sandstones by their depositional systems and component facies establishes a framework for comparison among stratigraphic units of different ages in different sedimentary basins. Unlike details of a stratigraphic sequence, which may vary between and within basins, characteristics of genetic facies tend to remain constant within a range determined by conditions of deposition. This classification helps provide a basis for determining the extent to which geologic and engineering knowledge gained in the study of one formation can be applied to the study of another.

Nine principal clastic depositional systems can be classified into continental, shoreline (marginal marine), and marine environments, and the nine systems can be subdivided further. For example, the fluvial system can be divided into braided streams, fine-grained meanderbelts, coarse-grained meanderbelts, and stabilized distributary channels. Each of these subclasses has distinctive sand-body geometry, texture, and distribution of internal sedimentary structures. Similarly, deltas can be divided into river-dominated types that have digitate to lobate geometries and into wave-dominated types that have cuspate geometries.

The thickness of a sandstone depends on sediment supply, water depth, and rate of basin subsidence. Thick sandstones generally form when the products of repetitive depositional events stack vertically, which introduces layering that can be detrimental to hydraulic-fracture stimulation. The amount of sediment input, basin subsidence, and sea-level changes are the main factors that control the vertical sequence of deposits. Clean (low clay content) sandstones, which generally make the best reservoirs, are deposited in environments where physical processes cause segregation of the bed-load (sand and gravel) and suspended-load (silt and clay) components of the sediment dispersal system. The high energy of the river channel or marine shoreface (the narrow zone affected by wave action) efficiently segregates the coarse and fine sediment fractions. Processes at the distributary mouth bar of delta systems are also efficient sediment sorters. The cleanest shales (having the lowest sand and silt content), which are the best barriers to hydraulic-fracture growth, form in quiet, low-energy environments, such as a lagoon or deep-marine basin. Transitional environments are common between the zones of highest and lowest energy, in which muddy sandstones and sandy mudstones are deposited. Only in special cases (during marine transgression, for example) are the clean sandstones that make the best reservoirs bounded by thick shale deposits that make the best barriers to fracture growth. The stress contrast between reservoir sandstones and the overlying and underlying beds is critical to hydraulic-fracture design, and rock mechanical properties of these beds can vary as a result of subtle contrasts in rock composition and texture.

Reservoir Composition and Diagenesis

Original porosity and permeability of sandstones are determined by their depositional environment, but diagenesis can significantly alter reservoir characteristics after deposition.

Most tight gas reservoir sandstones had moderate to high porosity and permeability at the time of deposition, but compaction and precipitation of authigenic mineral cements from aqueous pore fluids during burial have destroyed much of the original intergranular (primary) porosity. Older and deeper sandstones typically have lower porosity than do younger or shallower sandstones because they have undergone more extensive compaction and cementation. The importance of time for these porosity-reducing reactions to occur is evident from the age of most of the tight gas sandstones in the United States, which are Paleozoic (570 to 245 Ma) or Mesozoic (245 to 66 Ma). The only major Tertiary (66 to 1.6 Ma) tight gas sandstones are the Wilcox and Vicksburg of the Texas Gulf Coast, which have been deeply buried.

In addition to providing information on porosity and permeability distribution, study of the mineral composition of tight gas reservoirs is necessary for calibrating the log response of the reservoir and adjacent nonreservoir rocks in the formation. Composition and volume of detrital grains, clay matrix, and authigenic cements, as well as the type of pores, size of pore throats, and distribution of clays are correlated to log response and petrophysical properties such as permeability, porosity, pore-throat diameter, water saturation, and rock strength.

Information on the composition and distribution of minerals and pores in tight gas sandstones is derived primarily from thin-section point counts, X-ray diffraction analysis, and scanning electron microscopy (SEM). Framework-grain composition of a sandstone is typically expressed as the ratio of quartz:feldspar:rock fragments (QFR), which are the "essential grains" that are used to classify a sandstone. Quartz is the most abundant detrital mineral in most sandstones. If other minerals, such as feldspars or metamorphic rock fragments composed dominantly of mica, are unusually abundant, log analysts take this into account by using a different grain density. An abundance of feldspar grains, many of which are unstable and dissolve in the burial environment, may indicate that secondary porosity affects the porosity network. Abundant rock fragments, particularly metamorphic and sedimentary rock fragments, may indicate that the sandstone has undergone loss of porosity by ductile grain deformation.

Petrographic analyses of framework mineralogy, porosity, clay content, and clay distribution reveal compositional controls on rock strength. This information can then be combined with well-log analyses to yield fairly accurate predictions of rock strength and mechanical properties in treatment intervals and potential fracture barriers.

Fluid and gas in a sandstone flow most readily through well-connected, intergranular pores. In most tight gas sandstones, the intergranular pore network has been almost completely occluded by precipitation of authigenic cements. The result is that narrow, slot-like apertures between pores provide the major connectivity for fluid flow, and these narrow slots are closed easily by increasing pressure (effective stress). Thus, to measure permeability in tight gas sandstones accurately, one must analyze core under net overburden pressure conditions (stressed permeability), not at ambient surface pressure (unstressed permeability).

In many tight gas sandstones, the most abundant macropores (pores having pore-aperture radii of >0.5 μm) are secondary pores formed by dissolution of detrital grains, particularly feldspars. Secondary pores provide pore volume for gas storage, but they generally are connected only by the remaining narrow, intergranular pores. Therefore, permeability in tight gas sandstones containing mostly secondary pores is still controlled by the highly occluded intergranular pore network. Micropores (pore-aperture radii of >0.5 μm) are common in some tight gas sandstones, such as the Frontier Formation in the Green River Basin, but microporosity contributes little to permeability. Formations that have abundant microporosity may be interpreted from logs as having high porosity, but they have low permeability.

Tight sandstones can be divided on the basis of pore geometry into (1) sandstones that have open intergranular pores whose pore throats are plugged by authigenic clay minerals, (2) sandstones that have intergranular pores that have been largely occluded by authigenic cements (mainly quartz and calcite) and reduced to narrow slots that connect large secondary pores formed by grain dissolution, and (3) muddy sandstones that have intergranular volumes filled by detrital clay matrix and porosities that are mainly microporosities. According to recent surveys, Type 2 sandstones are the most common tight gas reservoirs, and most of the 24 sandstones in the 1992 atlas are Type 2 [23]. Sandstones that are exclusively Type 1 are rare, but many of the formations discussed in this atlas are Type 2 sandstones that also contain authigenic clays plugging pore throats. The poorest reservoirs in many low-permeability formations are Type 3 sandstones, and they probably do not contribute significantly to total gas production. The low-permeability, downdip part of the Olmos Formation is an example of a Type 3 sandstone. Type 3 sandstones are poor reservoirs because they have low porosity and permeability from the time of deposition as a result of an abundance of detrital clay that was either deposited with the sand or mixed in shortly after deposition by burrowing. Compaction further reduces porosity, so that Type 3 sandstones typically have no visible macroporosity. Although log-measured porosity may be as high as 10 percent, the porosity is all microporosity, and the sandstone has very low permeability.

Diagenetic complexity in Type 2 low-permeability sandstones varies considerably; the Travis Peak provides an example of a relatively simple system. There, although sandstones contain many different authigenic minerals, quartz is the most abundant porosity-occluding cement. As the volume of quartz cement increases with increasing burial depth, the volume of intergranular primary porosity decreases and permeability also decreases [41]. Average porosity and permeability can be predicted by depth in this formation. The Frontier Formation in the Green River Basin is a more complicated system. Quartz cement is the main control on porosity in some areas along the Moxa Arch, but in other areas calcite cement dominates. As a result, no trend emerges in either porosity or permeability with burial depth [14].

Authigenic clay minerals have an effect on the producibility of tight gas sandstones beyond simple porosity reduction. Because of their high surface-to-volume ratio, clays increase water saturation, which decreases relative permeability to gas. The relative influence on permeability of the main types of clay minerals varies in tight gas sandstones. Kaolinite generally occurs in compact clusters inside secondary pores, so it has the least effect on permeability. Chlorite flakes commonly line primary pores and thus have an influence greater than kaolinite of decreasing permeability. Illite and mixed-layer illite-smectite occur as fibers that have high surface areas and thus the greatest effect in reducing permeability. The presence of fibrous illite in a sample can jeopardize accurate permeability measurements from core plugs. Conventional core analysis of illite-bearing sandstones can indicate unrealistically high permeabilities caused by the collapse of illite fibers during drying.

Clay minerals in sandstones can also cause production problems because they are sensitive to completion fluids. Iron-rich chlorite will react with acid and form iron hydroxides that reduce permeability if the treatment liquids are not properly chelated. Swelling clays, such as smectite or mixed-layer illite-smectite with a high percentage of smectite layers, are sensitive to fresh water. Many of the 24 formations reviewed by Dutton and others in the atlas have a high percentage of illite layers, and thus they are not very sensitive to fresh water. A more difficult problem is reducing the permeability that results when water saturation increases as a result of drilling or stimulating a low-permeability formation.

Natural Fractures and Structure

Most rocks near the earth's surface (<3 to 6 mi deep) are brittle-elastic materials responding to natural stresses. Consequently, under the influence of extension, compression, flexure, uplift, cooling, and fluid migration, many rocks acquire networks of fractures of various types and sizes, which can be classified according to the relative movement of the fracture walls. Fractures having movement perpendicular to the fracture plane are *extension* or *opening-mode fractures*, whereas fractures having lateral displacement parallel to the fracture plane are *faults*. The shape of fractures, their associated infilling minerals, and characteristic fracture patterns can be used to classify fractures further and define fracture style and architecture. Reservoir rocks may contain both extension fractures and faults that range from microfractures normally only visible under the microscope to large fractures and faults thousands of feet in size.

Natural fractures are commonly observed in core from low-permeability-sandstone reservoir rocks, although many of these fractures are nearly vertical and therefore scarcely prone to intersection by vertical boreholes. Fractures are thus locally abundant in the subsurface, even in areas distant from structural perturbations such as folds and faults. In many cases, these fractures have been open or partly open in the subsurface, and locally they are associated with abrupt inflows of gas into the wellbore. Most documented fracture porosity values are low (a few percent and generally <1 percent). Recently fractures in several of low-permeability reservoirs have become targets for horizontal drilling, and in some cases increased gas production has been linked to fractures observed in core or on well logs from horizontal wells.

Knowledge of fracture occurrence, orientation, and pattern is important for engineering evaluation and development of reservoirs having low matrix permeability and for correct placement of deviated and horizontal wells designed to cross fractures. The full impact of fractures on fluid flow or engineering operations in most low-permeability-sandstone reservoirs has not been quantitatively assessed. Natural fractures likely play a key role in production from parts of most, if not all, low-permeability-sandstone reservoirs based on the disparity observed in some reservoirs between permeability measured on core samples and that implied by production histories. Fractures having marked effects on reservoir performance have been described from the Cotton Valley sandstone in the East Texas and North Louisiana basins, the Mesaverde in the Piceance Basin, the Frontier Formation in the Green River Basin, and the Davis Sandstone in the Fort Worth Basin, among others.

In addition to providing pathways for fluid movement locally, recent engineering analyses have also confirmed geologic predictions that natural fractures can profoundly affect the way induced hydraulic fractures grow. The growth of multiple fracture strands in naturally fractured intervals has been postulated to reflect pressure anomalies detected during hydraulic fracture treatments. Opening of natural fractures could account for the wide scatter of microseismic signals detected after hydraulic-fracture treatments, which were monitored using in-well geophones, and evidence from some basins that hydraulic fractures have grown parallel to the natural-fracture rather than the maximum-horizontal-stress direction [68]. Hydraulic fracturing suggests that natural fractures need to be considered in hydraulic-fracture-treatment design.

Fractures can be classified according to the processes that produced them, and knowledge of the processes that have affected a formation can aid prediction of overall fracture patterns and abundance in a formation or area. The main processes that contribute to fracturing in reservoir sandstones are folding, faulting, progressive subtle changes in basin shape resulting from regional shortening or extension and stretching due to tectonic or burial loading, unloading, cooling, and migration of fluids. Because all of these processes can act together or separately to produce fractures, fractures having different origins can coexist in a reservoir interval.

Although regional fractures commonly occur in subparallel sets, sets generally show variable spacing and patterns may change gradually or abruptly on both regional and local (field, interwell) scales. Such patterns can be documented and predicted. Reservoir fractures are arranged in networks that reflect the reservoir structure, the history of burial and tectonic loads that caused fracture propagation, and the evolving physical properties of the rock. Fracture-network interconnectivity and patterns of mineral fill within fracture networks control the size and shape of the rock volume contacted by a given borehole intersecting the network.

Faults are common geologic features that are a type of reservoir heterogeneity occurring in tight gas sandstones in a wide spectrum of sizes. Whereas large faults can compartmentalize reservoirs by juxtaposing reservoir and nonreservoir rocks, small faults may also be barriers to fluid flow as a result of grain breakage and porosity reduction, even where faults produce sandstone-on-sandstone contacts. Normal faults are common features of many Gulf Basin reservoirs such as the Lobo Wilcox and Vicksburg. Reverse faults occur locally in some sandstones adjacent to the Cordilleran thrust belt, such as the Frontier and Mesaverde, and strike-slip faults are possibly features of some Abo reservoirs. Data on faults in a given reservoir are commonly incomplete and affected by sampling bias. Short faults with small throw are generally invisible on seismic lines, and data from infill wells, where available, is seldom adequate to illuminate fault patterns in areas distant from these wells.

Natural fracture analysis, too, is hindered by obstacles to fracture sampling. Even simple fracture network patterns are difficult to impossible to document using conventional methods in vertical boreholes: fractures commonly escape detection on logs or in core. Detailed information on fracture density, connectivity, and orientation patterns currently can be obtained only from outcrop studies of reservoir analogs (exposed reservoir-facies rocks having structural histories similar to target horizons). Well tests and other engineering tests have provided little insight into natural fracture systems; commonly oversimplified representations of fracture networks are used to interpret such tests, often obscuring the effects of natural fractures on well tests and long-term reservoir behavior.

Although prediction, detection, and characterization of natural fractures are keys to reservoir assessment, to evaluate a reservoir successfully is a challenge. The effect of fractures on production depends on, among other factors, the relative permeability, porosity, and interconnectivity of the fracture network compared with that of the matrix rock. Fracture connectivity, or the distribution of fracture-occluding minerals in fracture systems, has not yet been successfully predicted on the prospect scale. The cumulative effect of long exposure to fracturing processes associated with tectonism, burial, uplift, and migrating fluids should work to produce an interconnected, conductive fracture network in older rocks. However, diagenetic processes of mineral precipitation tend to fill and close fractures. The intense faulting that characterizes the Tertiary (Eocene) Lobo Wilcox trend shows that such generalized models are no substitute for direct measurement of fractures and formation-specific predictive models.

Stress

Stress directions and stress contrasts in low-permeability sandstone reservoirs are important to the design of engineering operations in these rocks. Hydraulic fracturing is an effective stimulation method for low-permeability reservoirs, and hydraulic fracture growth directions and heights are key variables in hydraulic fracture treatment design in all of the sandstones described in this report. Because under typical reservoir conditions, the growth direction of hydraulic fractures tends to parallel maximum horizontal stress (SHmax), knowledge of principal stress directions is necessary for effective placement and stimulation of wells. This information is also important where open natural fractures contribute to production because open fractures may be preferentially aligned parallel to SHmax.

The contrast in the magnitude of the minimum principal stress between different beds is one of the key factors governing the vertical growth of a hydraulic fracture. If hydraulically created fractures grow significantly taller in the vertical direction than specified in treatment design, then fracture width and length will be less than anticipated, and strata above and below the treatment interval may be inadvertently intersected by treatment fractures, which may damage the well.

Intraplate tectonic stresses such as those that affect virtually all low-permeability gas reservoir rocks are mostly the result of plate tectonic forces acting on the lithosphere. Regional maps of current stress directions are thus useful tools for predicting approximate maximum horizontal stress directions on the local (field or interwell) scale. Analysis of tectonic history helps predict paleostress directions and the orientation of natural fractures. For most of eastern North America, midocean-ridge push forces cause a large province of generally north-northeast-trending maximum horizontal stress, the midplate compression province, which extends east from the Rockies to near the Mid-Atlantic Ridge.

Worldwide, most intraplate stresses are compressional, but a complex extensional stress province exists in the western United States: the Cordilleran extensional province. Such provinces commonly have elevated topography and heat flow. The Cordilleran province also comprises several domains having contrasting directions of maximum horizontal stress. This variability in stress orientation and the limited resolution of regional stress-direction maps that arises from sparse well data make stress directions in some western basins challenging to predict.

For example, evidence conflicts about stress directions from the Frontier Formation in the Green River Basin [68]. Stress directions in the formations studied in this project have been determined by various GRI contractors using several methods. One of our roles has been to synthesize and interpret test results in their geologic and tectonic context and according to the rock's composition and microstructure.

GRI research projects have shown that cores and stress tests can be used to calibrate log data so that an in situ profile can be obtained using acoustic data, density data, and estimates of formation rock type (if profiles are properly calibrated with stress tests). In conjunction with burial history, rock composition—particularly the volume of pore space and the amount and distribution of clay minerals—can profoundly affect rock strength and thus measured stresses, and information on diagenetic patterns can be used to predict rock properties and help calibrate stress profiles based on geophysical well log suites and stress tests. Using data generated by the Bureau, several research groups and other GRI contractors have attempted or are in the process of such analyses.

SYNOPSIS OF RESEARCH RESULTS

In addition to developing general principles that apply to many formations, this project has produced specific, in-depth geological and reservoir-property analyses of several important low-permeability reservoir formations.

East Texas Studies: Travis Peak Formation

The main goal of the geologic studies of the Tight Gas Sands Program in East Texas was to document the geologic framework of the Travis Peak Formation (fig. 2). Insights gained from this multifaceted study increased understanding of the geologic controls on distribution and behavior of Travis Peak tight gas reservoirs. Geologic studies in East Texas thoroughly characterized low-permeability gas reservoirs by determining (1) the size, orientation, and

(a) (b)

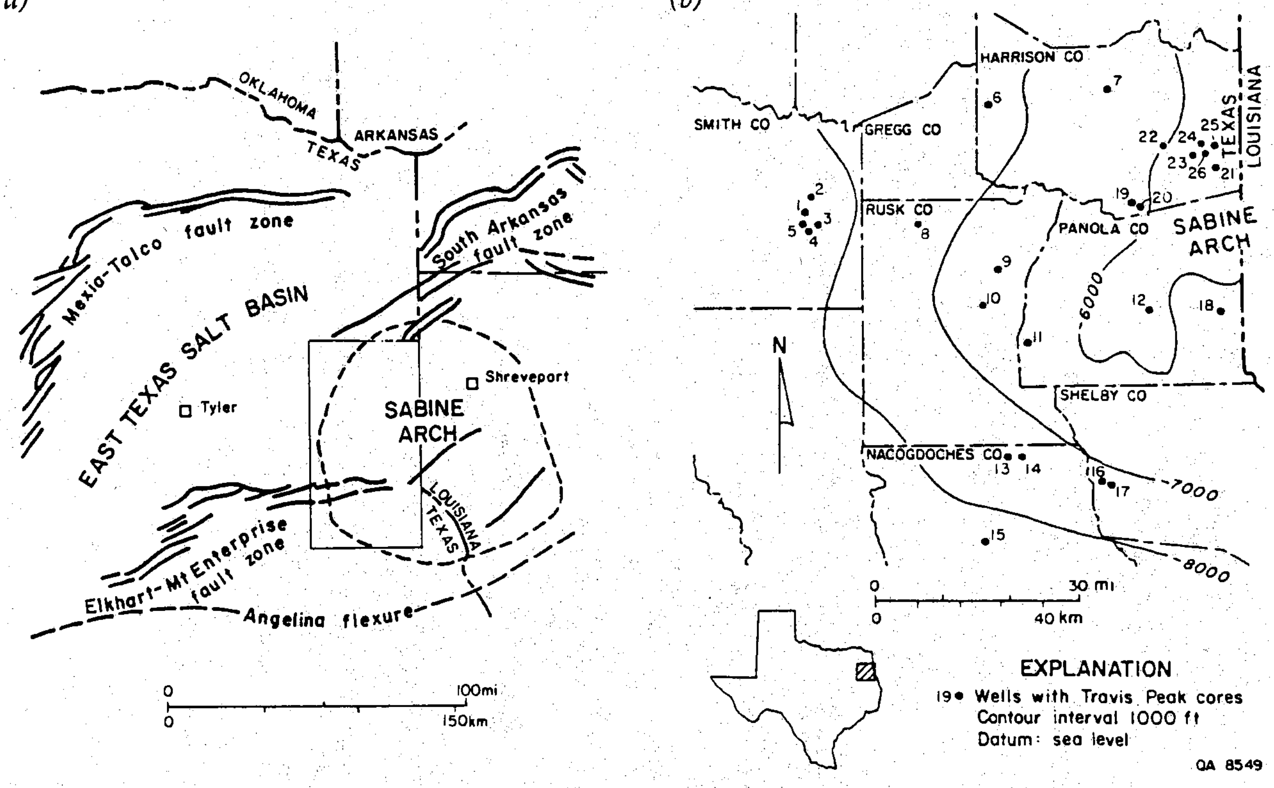

Figure 2. The Travis Peak Formation study area and wells in East Texas (from [27]). (a) Structural setting of the Travis Peak Formation, East Texas. (b) Wells for which Travis Peak cores are available and structure on the top of the Travis Peak. Well names are reported in Dutton and others [27], their table 1.

distribution of reservoir sand bodies, (2) the mineral composition of reservoirs and their response to geophysical logs, (3) the variability in porosity and permeability with depth, (4) natural fracture occurrence and orientation, and (5) the direction of in situ stress, which controls hydraulic fracture propagation. In addition to reaching specific conclusions about the Travis Peak, this study also provided a methodology for future geologic studies of other low-permeability, gas-bearing sandstones. Stratigraphic, petrographic, and structural studies formed the three main areas of geologic investigation that were needed to characterize this tight gas sandstone.

Mapping and core description studies indicate that Travis Peak depositional systems in this region of the East Texas Basin include a braided- to meandering-fluvial system that forms most of the Travis Peak section, deltaic deposits that are interbedded with and encase the distal part of the fluvial section, paralic deposits that overlie and interfinger with the deltaic and fluvial deposits near the top of the Travis Peak, and shelf deposits at the downdip extent of the Travis Peak. Shelf sediments interfinger with and onlap deltaic and paralic deposits, and the stratigraphy of the upper interbedded sandstone-mudstone interval implies retrogradational (onlapping) depositional conditions.

Stratigraphic correlation of sandstones and interbedded mudstones provides a basis for identifying Travis Peak reservoirs and estimating their extent and geometry. Reservoir quality and geometry vary with the original depositional processes that controlled sediment lithology, texture, and bedding, in addition to the degree of diagenesis. Sandstones at the top of the formation that were deposited in paralic and meandering-fluvial environments are thin (average 10 ft) and are separated by thick mudstones. In most of the lower parts of the Travis Peak Formation, sandstones are dominantly braided fluvial. The braided-stream system consists of stacked sandstones that individually range from 10 ft to >50 ft in thickness and average 21 ft in thickness. Best quality reservoir sandstone exists in wide bands oriented parallel to depositional dip.

Petrographic studies indicate that the Travis Peak Formation contains mainly fine- to very fine grained sandstone, muddy sandstone, silty sandstone, and sandy mudstone. True claystones that could provide stress barriers to contain hydraulic fracture growth are rare. The sandstones are mineralogically mature, consisting of quartzarenites and subarkoses. Well-sorted sandstones had high porosity and permeability at the time of deposition, but their reservoir quality has been reduced by compaction and cementation. Cementation by quartz, dolomite, ankerite, illite, and chlorite and introduction of reservoir bitumen by deasphalting have reduced porosity to <8 percent and permeability to <0.1 md throughout much of the formation.

Diagenetic studies indicate that structurally deeper Travis Peak sandstones are more intensely quartz cemented than are shallower sandstones. This variability in cementation results in differences in mechanical properties, porosity, and permeability between upper and lower parts of the Travis Peak. Furthermore, differences in diagenetic history between fluvial and paralic sandstones have resulted in fluvial sandstones that have an order of magnitude higher permeability than paralic sandstones at all depths. Because of the correspondence between extensive quartz cementation and fracture occurrence, open natural fractures should be abundant in highly cemented sandstones and log responses can be calibrated with core and used to identify beds prone to contain natural fractures. Natural fractures may contribute to production in Travis Peak sandstones that have very low matrix permeability.

A single producing reservoir sandstone in the Travis Peak can cover several thousand acres, but maximum drainage areas are generally <80 acres per well. Hydraulic fracture half-lengths range from 100 to 500 ft, far below the lateral dimensions of the sandstones. Owing primarily to uniform stresses and an absence of vertical barriers to fracture growths, circular, east-west-oriented fractures will form that will vertically connect as many as eight stacked sandstones. Predicting the propagation direction of hydraulically induced fractures is a key part of completion strategy, and geologic studies of core show that borehole breakouts and drilling-induced fractures in core can be used as inexpensive and reliable methods of predicting horizontal stress directions and the direction of hydraulic fracture propagation. Hydraulic fractures propagate subparallel to the east-northeast strike of the natural fracture; thus, hydraulically induced fractures may intersect few natural fractures.

Among the effects that natural fractures can have on well treatments are increased leakoff, fracture branching, and curvature. Fracture branching could cause high treatment pressures and spoil treatment results if not accounted for in treatment design. Geologic models indicate that natural fractures are unlikely to be closely spaced in the upper Travis Peak sandstones and that special precautions for treating naturally fractured rock are not required in the upper zone, but in the lower Travis Peak, natural fractures are locally extensively developed.

Green River Basin: Frontier Formation

The main goal of the geologic studies of the Tight Gas Sands Program in the Green River Basin, Wyoming, was to document the geologic framework of the Frontier Formation (fig. 3). Results are summarized in Dutton and others [14] and other reports and papers described in the annotated bibliography. Insights gained from this multifaceted study increased the understanding of geologic controls on the distribution and behavior of the Frontier tight gas reservoir.

Gas producers directly benefit from this research because the collection and assimilation of geologic information can lead to improved gas recovery and lowered completion costs through better field-development and well-completion programs in the Frontier Formation and similar tight gas sandstones. The results of petrographic examination of two potential pay intervals in a Frontier well are an example of how geologic characterization can benefit an operator. Log-calculated permeability determined by the Geochemical Logging Tool** (GLT) matched core-measured permeability in one interval but not in the other. By looking at thin sections of the two potential pay zones, we determined that one of the intervals had abundant microporosity but little intergranular primary porosity. Log-derived permeability for this interval was too high

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

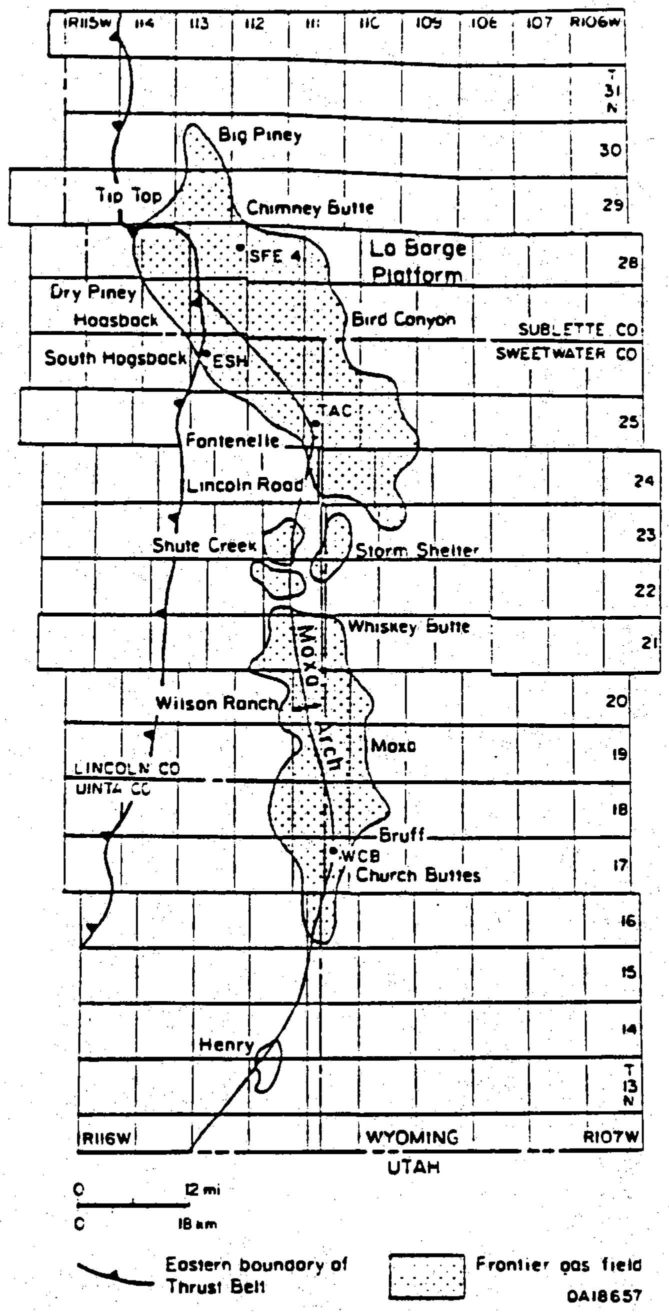

Figure 3. Map of major Frontier fields associated with the Moxa Arch, western Green River Basin [23]. Names of selected Frontier gas fields are shown. S. A. Holditch & Associates SFE No. 4-24 (SFE 4) and GRI cooperative wells Enron South Hogsback No. 13-8A (ESH), Terra Anderson Canyon No. 3-17 (TAC), and Wexpro Church Buttes No. 48 (WCB) shown.

because log-derived porosity included abundant microporosity as effective porosity. The other interval had more primary porosity and less microporosity, so the log-derived permeability was correct. On the basis of the petrographic information, the operator was able to identify pay zones using the GLT log in combination with a resistivity log.

Mapping and core description studies indicate that the main depositional and stratigraphic controls on distribution and quality of Frontier reservoirs are sandstone continuity and detrital clay content. Frontier production trends reflect sandstone distribution and continuity. The Second Frontier was deposited in a fluvial-deltaic system having prominent delta-flank strandplains. Marine shoreface and fluvial channel-fill sandstones are the reservoir facies. On the La Barge Platform, the widespread productivity of the Second Bench can be attributed partly to the remarkable continuity of this marine shoreface sandstone. The First Bench contains numerous discontinuous fluvial channel-fill sandstones, and only those wells penetrating these channels typically have First Bench production. However, First Bench channel-fill sandstones are the primary reservoir facies in the Second Frontier along the south part of the Moxa Arch where Second Bench upper shoreface sandstone is commonly absent owing to erosional truncation. Fluvial channel-fill sandstones form southeast-trending belts, which are a few miles wide, several tens of feet thick, and which are separated by interchannel shale and sandy shale. Within the channel belts, clean sandstone occurs as discontinuous lenses as much as 20 ft thick that are interlayered and laterally gradational with mud-clast-rich shaly sandstone. The marine shoreface facies forms a continuous northeast-thinning sheet of sandstone, 40 to 120 ft thick. Clean sandstone is best developed near the top of the shoreface facies in northeast-oriented trends 5 to 40 ft thick. The Fourth and Fifth Benches of the Second Frontier and the Third and Fourth Frontier, which were deposited in mud-dominated coastal plain and marine shoreline systems, contain isolated sandstones that are locally productive.

Detrital clay content exerts a strong influence on the porosity and permeability of Frontier sandstone before diagenetic modification, and detrital clay content is controlled by depositional environment. Most Frontier sandstones along the Moxa Arch were deposited in one of three depositional environments: lower shoreface, upper shoreface, and fluvial channel. Frontier lower shoreface sandstone is characterized by abundant pore-filling detrital clay matrix, which was mixed into the sand by burrowing organisms on the sea floor. In Frontier lower shoreface sandstone, permeabilities are generally low, although porosities may be similar to those in the other sandstone facies. Frontier upper shoreface sandstone was free of clay at the time of deposition because in the shallow-water upper shoreface environment strong currents winnow fine-grained sediment and inhibit burrowing organisms. On the La Barge Platform, the most prolific Frontier reservoirs lie in Second Bench upper shoreface sandstone. Frontier fluvial channel-fill sandstone contains abundant sand- and gravel-sized mud rip-up clasts, which deform into pores and pore throats during compaction. The channel-fill facies typically consist of mud-clast-rich sandstone interlayered, and laterally gradational, with sandstone that is relatively free of mud clasts. Thus, clean sandstone typically occurs as discontinuous lenses within the channel-fill facies. Upper shoreface clean sandstone, on the other hand, consistently occurs at the top of the progradational shoreface sequence and therefore is a more predictable target.

The major causes of porosity loss in Frontier sandstones during burial diagenesis were mechanical and chemical compaction and cementation by calcite, quartz, and authigenic clays. Quartz cement is most abundant in deeply buried fluvial channel-fill sandstones at the south end of the Moxa Arch and in the Green River Basin. Calcite cement is most abundant in Frontier sandstones deposited in lower shoreface environments. Both upper and lower shoreface sandstones from the Hogsback area at the north end of the Moxa Arch contain significantly more calcite cement than do shoreface sandstones in either the Fontenelle or Church Buttes areas.

Despite extensive diagenetic modification, reservoir quality in the Frontier Formation is best in facies that had the highest porosity and permeability at the time of deposition. Original intergranular porosity has been substantially reduced in these clean sandstones by compaction and precipitation of authigenic cements, but they still retain higher porosity and permeability than do sandstones that have abundant detrital clay matrix. Thus, exploration for Frontier reservoirs should focus on locating clean sandstones deposited in high-energy depositional environments. The reservoir intervals in the wells in this study are mainly in clean, upper shoreface and fluvial channel-fill sandstones.

Nevertheless, reservoir quality in clean sandstones is variable because diagenetic modification is highly variable. Whereas some upper shoreface sandstones have low porosity and permeability because of abundant calcite cement, other sandstones from the same depositional environment contain little calcite and may have relatively high porosity and permeability. Similarly, upper shoreface sandstones having abundant rock fragments have lost more intergranular porosity by mechanical compaction than have quartz-rich upper shoreface sandstones. Some fluvial channel-fill sandstones are extensively cemented by quartz, and others are not. Fibrous illite and MLIS can drastically reduce reservoir permeability in any facies.

The general distribution of quartz cement is predictable because a strong correlation exists between volume of quartz cement and depth. Thus, fluvial channel-fill sandstones at the deeper, south end of the Moxa Arch can be expected to contain a greater volume of quartz cement than can fluvial channel-fill sandstones from the north end. Occurrences of calcite and fibrous illite cements exert a powerful control on porosity and permeability in Frontier reservoirs, but they cannot be predicted on the basis of current knowledge. However, patterns in the distribution of these cements provide general guidelines of where they are most likely to occur. Fibrous illite and MLIS are most abundant in upper shoreface samples from Fontenelle field. Calcite cement is most plentiful in the Hogsback area on the northwest part of the La Barge Platform. Calcite cement commonly is most abundant at the top of clean, well-sorted sandstones, directly below the contact with an overlying muddy sandstone. Once a well has been drilled, zones of intense calcite cementation can be identified on logs, for example by high resistivity response. Intervals of intense calcite cementation should not be counted as part of the pay in a well.

Open fractures exist in Frontier Formation core, and production and fracture treatment results suggest that natural fractures locally play significant roles. The sparse occurrence of natural fractures does not necessarily mean that they are an unimportant reservoir element in these rocks. Fracture networks in outcrops that likely resemble fractures existing at depth have attributes such as wide spacing and great lateral extent that would tend to make them both effective as fluid conduits and difficult to intersect and detect by means of vertical wells.

Outcrop studies show that fractures are in networks where fracture connectivity is locally highly variable and anisotropic. For example, the direction of fracture strike can shift by 90° among adjacent beds. Moreover, fractures commonly are in discrete, irregularly spaced swarms separated laterally by domains that have few fractures, rather than in regularly spaced, orthogonal fracture sets. Because average strikes of fracture sets can be predicted from regional tectonic extension directions, an optimum direction for drilling in flat-lying rocks can be determined. More challenging to predict are fracture orientation in a specific bed, fracture density, and the probability of encountering a dense cluster of fractures using hydraulic fractures or horizontal wells. For predicting open natural fractures, the direction of maximum horizontal stress also needs to be examined.

Natural fracture swarms in the Frontier Formation are potential high-permeability "sweet spots" that can be included in reservoir models and targeted in exploration. In outcrop, swarms are separated laterally by domains commonly tens or hundreds of meters wide where fractures are markedly less common or not in contact with other fractures. Fluid communication between adjacent swarms, both laterally and vertically, is likely to be poor to nonexistent, resulting in elliptical islands (in plan view) where fracture permeability is high. This view of fracture patterns is in sharp contrast to conventional views in which regional fractures are in regularly spaced, orthogonal arrays. The implication for hydraulic fracturing and horizontal drilling is that good fracture targets can still be missed, even if hydraulic fractures or horizontal wells are correctly oriented in a direction that crosses fracture strike. Methods are needed for detecting fracture swarms and improving predictions of swarm spacing, length, and connectivity.

Reservoir heterogeneities resulting from fractures may be as pronounced as those produced by stratigraphic variations. The drastic differences in fracture-network connectivity and fracture density in otherwise similar upper shoreface sandstones is one piece of evidence for this heterogeneity. Another is clustered fracture patterns that are similar over a range of observation scales, showing that fractal concepts are a valid approach to describing fracture distributions in these sandstones. The discontinuous, fractal nature of fracture networks, such as those in Frontier Formation sandstones, should be incorporated in exploration plans and models that simulate flow in these reservoirs. Otherwise, using production results to predict the presence of natural fractures that could ultimately play a large role in production over the life of a well may be unwarranted. The well tests and production characteristics of variably interconnected fracture networks, over the short term, might mimic the behavior of a reservoir having only matrix permeability, yet the impact of fractures on drainage patterns and stress sensitivity over longer production times could be large.

Stress-direction indicators suggest north-trending SHmax but give inconsistent orientations of SHmax in the Frontier wells we studied. Borehole breakouts, coring-induced fractures, anelastic strain recovery, P-wave velocity anisotropy, and strength anisotropy tests each show large dispersion in inferred maximum horizontal stress direction. Wellbore breakouts and coring-induced fractures, which are generally among the most reliable methods, are poorly expressed. We interpret wellbore breakout data to show north-trending maximum horizontal stress. The scatter of stress directions from the methods we used may indicate that a low contrast in the magnitudes of horizontal stresses exists in the Frontier Formation on the Moxa Arch. This is compatible with the position of the western Green River Basin near a stress province boundary and with evidence from remote monitoring of hydraulic fracture growth that created fractures propagated to the east-northeast rather than to the north, parallel to inferred maximum horizontal stress. If this is the case, tensile strength anisotropy, in the form of natural fractures, is likely the main control on hydraulic fracture growth directions in these wells.

Val Verde Basin: Canyon Sandstone

The objective of the geologic study of the Canyon Sandstone formation was to develop a comprehensive description of the physical characteristics of the reservoir sandstones. To accomplish this task, it was necessary to (1) map regional and field-scale Canyon sandstone distribution, (2) interpret and characterize depositional systems and facies, (3) investigate how the diagenetic history of the sandstones has modified reservoir porosity and permeability, and (4) summarize preliminary observations of natural fractures in Canyon core. Although research on the Canyon Sandstone is ongoing, results-to-date are described in several reports and papers (see annotated bibliography).

The Canyon Sandstone tight gas play stretches mainly over the north and east parts of the Val Verde Basin in southwest Texas but also extends across the Ozona Arch, the south end of the Midland Basin, and the southwest margin of the Eastern Shelf (fig. 4). Cumulative gas production from Canyon Sandstone reservoirs is almost 2 Tcf and several trillion cubic feet of recoverable gas is thought to remain. Hamlin and others [61] summarized recent work on the stratigraphy and diagenesis of Canyon reservoirs in Sonora and Sawyer fields, Sutton County, and Marin and others [76] documented for the first time the occurrence and attributes of natural fractures in Canyon sandstones. These results are useful for designing more effective exploration and development strategies and improving design and modeling of hydraulic fracture treatments in the Canyon Sandstone.

Canyon sandstones were deposited in shelf-edge, slope, and basin-floor environments during the late Pennsylvanian and early Permian. The largest and most prolific fields, such as the Ozona, Sawyer, and Sonora fields, produce from thick sandstones in a slope setting, where

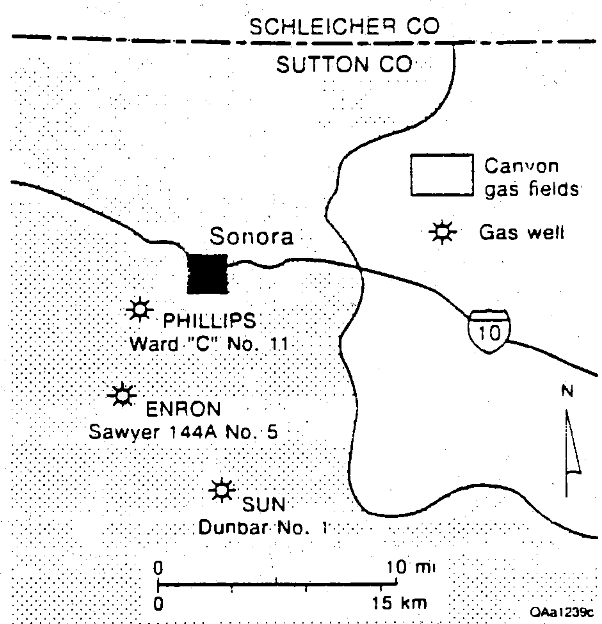

Figure 4. GRI cooperative wells in the Val Verde Basin, Texas (from [76]).

the Canyon is 1,000 to 3,000 ft thick and comprises complexly interbedded sandstones and shales (net sandstone reaching 1,000 ft). Canyon gas reservoirs lie at depths between 2,000 and 8,000 ft.

Most Canyon sandstones were deposited in submarine fan systems. During sea-level lowstands fluvial-deltaic systems transported sediments across exposed shelf areas and deposited them directly into basinal areas. Sediment input occurred at many locations along the shelf margins, forming wedge-shaped slope aprons composed of small, laterally coalesced submarine fans. The primary reservoir facies are submarine channel-fill and fan-lobe sandstones. On the inner or proximal part of the fan, isolated channel-fill sandstones, 20 to 100 ft thick and <0.5 mi wide, are enclosed in thick slope mudstones. The middle fan comprises a complex cross-cutting network of channel-fill and proximal fan-lobe sandstones and interchannel mudstones. Even the more sheetlike fan-lobe sandstones, because they formed in numerous small submarine fans, individually do not extend more than a few miles. The distal fan-lobe margins are composed of thinner but more laterally continuous sandstones interbedded with basinal mudstones.

Turbidites are the main sedimentary features of Canyon reservoirs. A turbidite, which may be characterized simply as massive to laminated sandstone overlain by laminated mudstone, records deposition by a waning turbidity flow. Wells in Sawyer and Sonora fields commonly penetrate as much as 1,000 ft of gross sandstone that is composed of hundreds of turbidites. Many Canyon reservoirs, although thick, are thus compartmentalized vertically by the fine-grained components of the turbidites.

Canyon reservoirs are typically composed of very fine to medium-grained sandstone, although coarser, locally conglomeratic sandstone is present in the channel-fill facies. Intergranular detrital clay matrix is abundant locally, and even clean Canyon sandstones include numerous unstable rock fragments. Clay matrix and rock fragments are susceptible to porosity occluding and physical and chemical alterations. Intergranular cements, which also destroy porosity, constitute as much as 52 percent of rock volume in Canyon sandstone samples from

Sonora and Sawyer fields. Clean, matrix-free reservoir sandstones generally have <5 percent effective porosity and 0.1 md permeability.

The best matrix reservoir quality in Canyon sandstones commonly occurs in siderite-cemented zones. Siderite ($FeCO_3$) was one of the first cements to precipitate, and siderite volume ranges from 0 to 30 percent. Siderite-rich sandstones commonly occur in bedding-parallel layers that average 6 to 8 inches in thickness and are rarely >10 inches. Siderite also occurs in irregular patches that are typically 3 to 4 inches in diameter. The highest porosity in Canyon sandstones occurs in association with abundant siderite, possibly because early-formed siderite cement created a rigid grain framework that preserved intergranular porosity that would otherwise have been lost to mechanical compaction. According to Dutton and others [88], Canyon Sandstone layers that contain >10 percent grain-rimming siderite result from cementation shortly after deposition of deep marine sediments in an anoxic-nonsulfidic (postoxic) geochemical environment. Bacterial reduction of iron accompanying organic matter decomposition increased Fe^{++} in pore fluids, and in absence of sulfide, siderite precipitated. In samples from GRI Canyon cooperative wells, average porosity of siderite-rich sandstones (>10 percent siderite) is 7.9 percent, compared with 6.4 percent in siderite-poor sandstones. Similarly, the geometric mean of stressed permeability is higher in siderite-rich sandstones (0.042 versus 0.009 md).

Data obtained from three cored cooperative wells shows that natural fractures are locally abundant [77]. At least three distinct natural fracture classes coexist that have contrasting (1) distributions, (2) characteristic sizes, and/or (3) mineral fills. The most abundant fracture class comprises clay- or clay- and carbonate-filled fractures that are confined to siderite-cemented zones in sandstones. Owing to their clay content, these fractures locally may interrupt fluid flow or cause reservoir heterogeneity and anisotropy. Calcite- and quartz-cemented fractures are less common fracture classes. These fractures are larger than those in siderite layers and are partly open as a result of propping by diagenetic minerals. Our results show that fractures in Sonora Canyon sandstones should be considered for completion and stimulation design. For example, high treatment pressures observed in some Canyon Sandstone stimulations may be due to natural fractures promoting propagation of multiple fracture strands near the wellbore. Inconsistencies between hydraulic fracture strike and maximum horizontal stress may be due to natural fractures guiding hydraulic fracture growth.

North Texas/Oklahoma: Cleveland Formation

Low-permeability sandstones of the Upper Pennsylvanian (lower Missourian) Cleveland Formation compose major gas-producing reservoirs in the western Anadarko Basin of the northeastern Texas Panhandle. Although Cleveland reservoirs had produced >435 Bcf of natural gas as of January 1991 (according to Railroad Commission of Texas reports) and have an estimated 38 Tcf of gas in place, little published information is available on even the basic geology of the unit. The topical report on the Bureau's Cleveland study, which was distributed to GRI in November 1992, offers a firm geologic basis for other subregional and field-specific studies of the Cleveland.

Existing fields of the Cleveland gas play are restricted to folded and minor faulted zones that have deformed the northern occurrences of Cleveland sandstones in Ochiltree and Lipscomb Counties (fig. 5). Regional characterization of the lithostratigraphy, structure, depositional systems, and sequence stratigraphy of the Cleveland Formation will enable more accurate subregional and reservoir-scale geologic study. The ability to predict and explore for other possible Cleveland pay zones outside this region has been hampered by the limited published information regarding the regional and subregional lithostratigraphic, structural, and depositional architecture of the formation. The areal coincidence of abundant sandstone, vertically proximal potential source rock underlying the Cleveland reservoir facies (black shale marker bed at the top of the Marmaton Group and distal delta shales of the Marmaton and lower Cleveland), and potential trap-producing structures and facies pinch-outs throughout

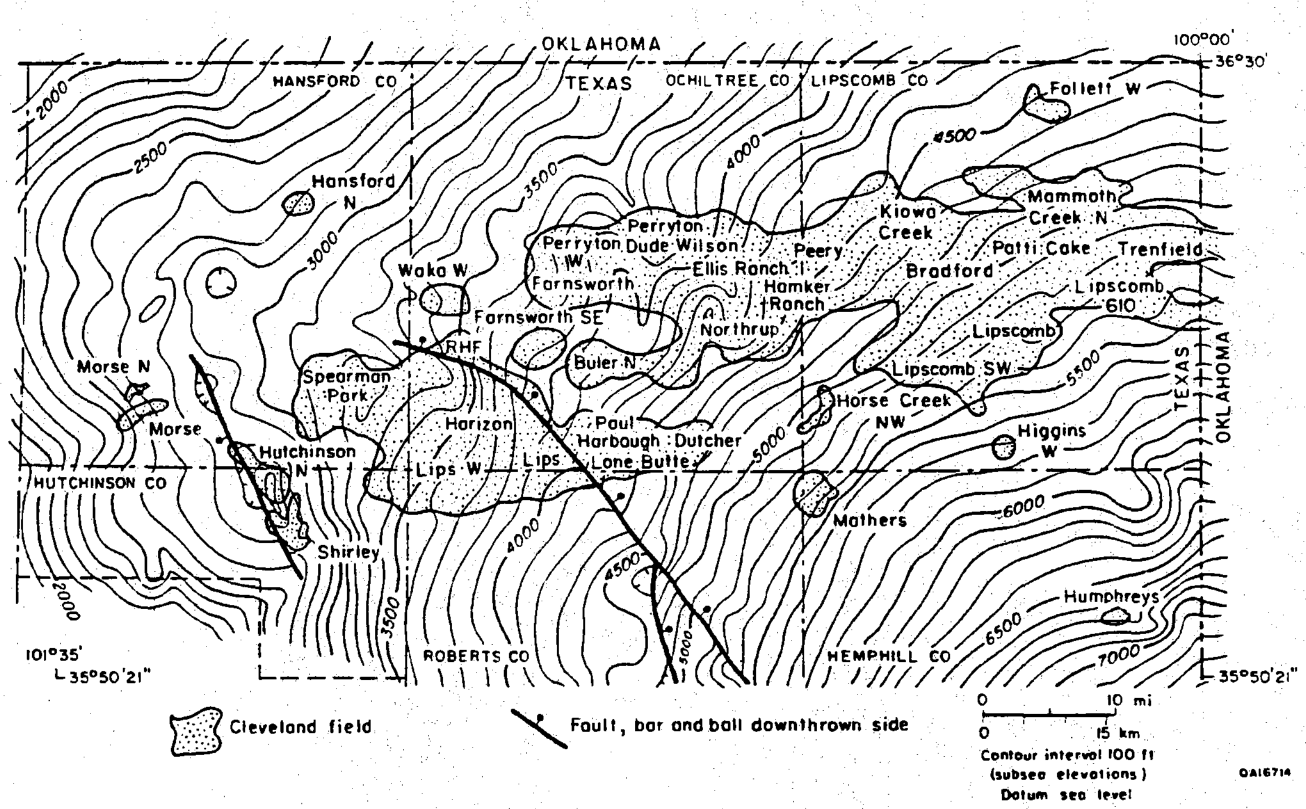

Figure 5. Map of major Cleveland hydrocarbon fields superimposed on structure-contour map of top of Cleveland Formation. All fields except Morse, Mathers, Higgins West, Humphreys, and Follet West had produced at least 1 Bcf and/or 1 Bcf equivalent (oil) as of January 1, 1990.

much of the western Anadarko Basin indicate the possibility of new field discoveries outside the known producing region.

The Cleveland Formation, a well-constrained lithostratigraphic division, is bounded by regionally continuous high-gamma-ray black shale marker beds that extend beyond the study area to the north and at least as far east as west-central Oklahoma and probably well beyond into the Anadarko Basin. The Cleveland section contains mostly siliciclastics between the Amarillo Uplift and the north part of the study area, where the sandstones thin markedly and grade into thin shale intervals between much thicker, massive limestone facies of the Kansas Shelf. To the south, Cleveland strata interfinger with wedges of granite wash along the north flank of the Amarillo Uplift. Eastward toward the deep Anadarko Basin, the thickening formation becomes shalier.

Reservoir sandstones originated in proximal delta-front and fluvial depositional environments. The lower to middle Cleveland comprises stacked, upward-coarsening deltaic intervals that prograded eastward and were fed by fluvial systems that had sediment sources west of the Anadarko Basin. These successions in cores can be divided into prodelta, distal delta-front, and proximal delta-front facies. A regional fluvial channel fill incises the uppermost deltaic cycles in most of the study area; incision is inferred to have occurred during a sudden drop in regional base level.

Distinctive trends of Cleveland thickness variation record penecontemporaneous structural elements that greatly affected sediment dispersal and accumulation patterns. Areas of thickest Cleveland (as much as 590 ft) mark a paleophysiographic basin in most of Lipscomb and Hemphill Counties that was formed by syndepositional faulting and localized downwarping along a monoclinal flexure at its south and north borders, respectively. The basin was the site of primary sand accumulation during Cleveland time. A generally east-west-trending paleohigh within a broad physiographic shelf platform updip to the west separates Cleveland siliciclastic deposits (in the south) from coeval carbonate facies (in the north). The Cleveland depositional shelf edge overlies a pronounced slope break in the Oswego shelf platform and marks the basinward limit of Cleveland delta progradation. Both the Oswego and Cleveland slope breaks were formed, and their geomorphic expression sustained, by differential subsidence. Structural activity during Cleveland time is partly an expression of the Pennsylvanian orogenic episode that affected most of the Anadarko Basin and surrounding highlands.

The siliciclastic interval between the Oswego Limestone and the Kansas City Formation can be divided into well-defined parasequences/parasequence sets (P) and systems tracts composing three sequences (S1 through S3). Sequence 1 (S1) includes the Marmaton Group (undivided) and the lower half to two-thirds of the Cleveland in most of the western Anadarko Basin. Marmaton P1 through P6 overlie a Type 1 sequence boundary that coincides with the top of the Oswego Limestone. P1 through P5 represent a series of westward-prograding, seaward-stepping, stacked delta and/or shoreface systems deposited during a relative sea-level lowstand. Subsequent retrogradation of deltaic/shoreface systems during rising relative sea level is recorded in the landward-stepping parasequences of Marmaton P6. A regional, fossiliferous condensed section (base-of-Cleveland marker bed) occurs at the top of this transgressive systems tract or straddles the boundary (maximum flooding surface) between the Marmaton transgressive systems tract and the overlying lower Cleveland highstand systems tract. Cleveland P1 through P3 form generally sandstone-bearing, seaward-stepping, stacked deltaic cycles that prograded eastward during a relative sea-level maximum. The top of P3 and locally of P2 is a regional erosional surface (Type 1 sequence boundary) created by incision of a westerly sourced fluvial system (P4, incised-valley system) during a rapid fall in relative sea level. Sandstones of Cleveland P2 through P4 compose the Cleveland reservoir facies in the north part of the study area. A relative sea-level rise followed, allowing aggradation of the valley fill and formation of the overlying retrogradational parasequence set that includes P5 and P6. Component systems tracts of the upper Cleveland (P7 through P10) and Kansas City Formations are thin, and they were dominated by carbonate and shale deposition, probably at the distal margins of progradational cycles sourced far to the east or southeast.

1993 National Survey of Tight Gas Sandstones

The *Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States* summarizes geologic, engineering, and production information for 24 low-permeability, natural gas-bearing sandstone reservoirs in 13 basins in the United States (fig. 1). The Federal Energy Regulatory Commission (FERC) has designated all but one of the units, the Davis Sandstone in the Fort Worth Basin, to be tight formations in specified areas under the definition of section 107 of the Natural Gas Policy Act (NGPA) of 1978. The 24 low-permeability formations in the atlas were selected either because they contain abundant natural gas reserves and resources or because the geologic and engineering data available for their characterization could apply to other, similar gas-bearing formations.

The 1993 atlas updates an earlier summary of low-permeability sandstones by Finley [29] titled *Geology and Engineering Characteristics of Selected Low-Permeability Gas Sandstones: A National Survey*. Considerably more geologic and engineering information now exists for the formations presented in the Finley report, and the atlas attempts to incorporate the latest publicly available literature on these and other gas-bearing formations in the United States.

The atlas includes production data for all formations except the "Clinton"–Medina, Berea, and Davis Sandstones. These data come from the report *Tight Gas Field, Reservoir, and Completion Analysis of the United States*, which was prepared by Energy and Environmental Analysis, Inc. (EEA) for the Gas Research Institute. The report summarizes cumulative production through 1988 from the formations covered in this atlas and lists estimates of ultimate recovery (defined as cumulative production through 1988 + proven reserves) from existing wells. Engineering data tables for each formation list other information from the EEA report, including the number of completions within the area of the formation that has been designated tight and average recovery per completion.

Formations were selected for the atlas because they are major producers of gas from low-permeability sandstone reservoirs or because a large amount of study has focused on them, or both. All formations listed by EEA as having estimated ultimate recovery of >500 Bcf are included. The EEA report did not cover the Appalachian Basin, but the two most prolific low-permeability Appalachian reservoirs, the "Clinton"–Medina and the Berea, are included. Several formations in the atlas were not in the Finley [29] report: the Wilcox and Vicksburg Formations of the Texas Gulf Coast, the Granite Wash in the Anadarko Basin, the Abo and Morrow Formations in the Permian Basin, the Canyon Sandstone of the Val Verde Basin, and the Dakota Sandstone in the Piceance Basin. These formations have been added because (1) drilling in them has been active since 1984, (2) more information about them is now publicly available, or (3) their resource potential as reported by EEA is significant. Conversely, some formations that were in the Finley report have been excluded in this volume. Some formations that Finley anticipated would be designated tight by FERC have not been (Oriskany and Tuscarora Sandstones, Appalachian Basin; Carter Sandstone, Black Warrior Basin; Cromwell Sandstone, Arkoma Basin; and Frontier Formation, Big Horn Basin). Other formations have been designated tight but have a low estimated ultimate recovery and so were not included: Hartselle Sandstone, Black Warrior Basin; Spiro Sandstone, Arkoma Basin; Sanostee Member of the Mancos Shale, San Juan Basin; Sego and Castlegate Sandstones in the Mesaverde Group and Mancos Shale, Uinta Basin; and Fox Hills Sandstone, Green River Basin.

An introduction to each basin in which the selected tight gas formations occur summarizes the age and location of the basin, its structural history and major tectonic features, the age and stratigraphic relations of all formations in the basin that have been designated tight (including formations not covered in detail in the atlas), and information on stress orientation. The basin introduction is followed by chapters on the major tight gas sandstones within that basin. Each formation summary is divided into (1) introductory information on thickness and depth of the formation, data availability, and previous studies, (2) depositional systems and reservoir facies, (3) composition and diagenesis of reservoir facies, (4) natural fractures, (5) engineering characteristics, and (6) production history.

The report reviews 24 formations that, either because of the large volumes of natural gas reserves contained within them or the data available for their characterization, are the most important tight gas sandstones in the United States. Assessment of these sandstone reservoirs indicates that geologic controls play a critical role in gas producibility and that these reservoirs share a number of key geological attributes. Perhaps a surprising result is that most of the tight gas reservoirs in this atlas are not immature, muddy sandstones having large volumes of diagenetically reactive detrital clay matrix, but rather are clean sandstones deposited in high-energy depositional settings whose intergranular pores have been largely occluded by authigenic cements (mainly quartz and calcite).

Just as in conventional oil and gas fields, reservoir genesis in tight gas sandstone reservoirs clearly influences gas accumulation and recovery. The major tight gas sandstone reservoirs surveyed herein were deposited most commonly in barrier/strandplain (10) and deltaic (8) depositional systems. Fluvial (2), shelf (2), slope and basin (2), and fan-delta (1) depositional systems make up the remainder. A survey of the largest conventional clastic oil reservoirs in Texas shows a comparable bias in hydrocarbon recovery toward wave-modified deltaic and barrier/strandplain reservoirs that together account for >60 percent of the estimated recoverable oil resource.

Depositional systems govern the physical processes under which sediment is deposited and thus influence sediment sorting, packing, and separation of fines, and these parameters determine the original porosity and permeability. However, production characteristics of low-permeability gas reservoirs are largely controlled by the diagenesis, or chemical and physical changes, that the sediment has undergone after deposition. Sediment composition, depth of burial, and age of the reservoir are important parameters in diagenetic alteration.

Further geological attributes critical to gas producibility of tight sandstones are natural fractures and stress directions. In order to achieve FERC tight gas designation, formations must produce gas at less than a specified rate before well stimulation; the exact production limits vary with formation depth. Economic viability of such formations will depend on the success of hydraulic-fracture treatments to stimulate greater flow rates. An understanding of the natural fracture systems will benefit design of completion practices and guide drilling strategies.

REVIEW OF TECHNOLOGY TRANSFER SUCCESS

Measuring the success of the dissemination of information is challenging. How and to what extent ideas, concepts, models, and specific facts about formations and reservoirs are acquired by the producer community, how they are perceived, and how they are used, are often difficult to judge quantitatively. Although improving methods to assess technology transfer success is a worthwhile goal (because it can lead to enhanced utilization of research results), it is beyond the scope of this report. However, we do present a few readily available measures of information transfer success showing that the results of our studies have been made available to the public.

Over the course of the project, topical reports, the Bureau of Economic Geology publications series, published papers, oral presentations, and workshops have been used to communicate research results to industry and the general scientific community: 17 Gas Research Institute topical reports and more than 95 other published works. Five Bureau Reports of Investigations and one Geological Circular have been published by the Bureau of Economic Geology, and at least three additional Bureau publications will appear in 1993. These reports and papers describe preliminary findings, summarize specific experiments and studies, and present final results of completed studies. In addition to these publications and for the purpose of facilitating Tight Gas Project engineering research activity, the Bureau also produced numerous written documents that are not formal publications, including preliminary geologic description reports and other documents describing core and other data collected in SFE and cooperative wells. Shortly after data collection, these reports were issued to other GRI contractors and to companies and operators involved in cooperative wells.

Topical reports communicate results efficiently because they are distributed directly to industry users, appear as part of a set of GRI project publications, and are made available through GRI's publication distribution system. The Bureau has contributed to GRI reports on SFE wells, which describe integrated reservoir characterization and engineering case studies in experimental wells.

The publication series of the Bureau of Economic Geology is advertised nationally to a mailing list of about 7,500 subscribers. More than 145 libraries and other geological surveys receive Bureau publications in cooperative exchange-of-publications agreements. Bureau publications are also distributed through over-the-counter sales. Six project-related Bureau publications have been issued, three are in press or in preparation, and over-the-counter sales of publications developed in the Tight Gas Sands Project have been steady. By 1989, more than 1,500 Tight Gas Sands Project-related BEG publications had been sold.

Another important medium for information transfer is peer-reviewed journals. These publications reach a wide international audience that includes not only other researchers but also key management personnel in industry who directly influence the resource development strategies and field operations that are used in their companies. Bureau workers have published 14 articles in peer-reviewed journals on topics directly related to work conducted on the tight gas project. On the basis of a conservative circulation estimate of 10,000 for each of these journals (for example, AAPG Bulletin circulation is 33,500), we estimate that these articles have reached more than 100,000 readers.

A total of 63 professional presentations, of which papers or abstracts would be published, were given concerning the Bureau's project research. Many of these were presented at large national or international conventions, where audiences can be substantial. We estimate that these presentations reached an audience of 4,400 engineers, geologists, and managers.

A total of 55 presentations that had no published papers or abstracts were made on various aspects of the Bureau's tight gas sandstone research. Many of these were given at local geological societies whose members actively explore and produce tight gas sandstones and thus can immediately apply information and technology developed through the GRI program. An additional 16 talks were presented in GRI and other workshops. We estimate that these talks and workshops of GRI-sponsored Tight Gas Sands research reached an audience of 3,500 geologists and engineers.

Direct discussions with industry workers, although informal, can convey a quantity of information developed in the project. Although fewer people are reached directly by these means than by publication and formal presentation, interpersonal communication commonly solves specific geologic and engineering problems.

Additionally, because of continuing tight gas sands research at the Bureau and the steady distribution of research results, the Bureau is perceived as a source of tight gas sand geologic information. Through telephone conversations, letters, visits, and informal meetings, the Bureau receives inquiries concerning specific tight gas reservoirs, fields, or wells, regional or basinwide geologic frameworks, and analytical techniques for characterizing tight gas sands. On average, Bureau workers involved in tight gas sands research receive three to five telephone or letter inquiries per month. Many of these inquiries lead to office visits during which research results are reviewed and discussed in depth. Because the project typically involves about four Bureau scientists, informal industry contacts average 200 to 250 per year.

The Tight Gas Sands Project has been singled out for several professional and technical awards. The paper *Petrography and Diagenesis of Lower Cretaceous Travis Peak (Hosston) Formation, East Texas*, which was presented at the 1986 annual meeting of the Gulf Coast Association of Geological Societies received the First Place Best Paper award and the A. I. Levorsen Memorial Award for excellence in presentation. The paper *Organic Geochemistry of the Lower Cretaceous Travis Peak Formation, East Texas Basin*, which was presented at the 1987 annual meeting of the Gulf Coast Association of Geological Societies, also received the First Place Best Paper award and the A. I. Levorsen Memorial Award. A paper titled *Fracture Trace Maps of Upper Cretaceous Pictured Cliffs Sandstone Pavements*, which describes fracture studies of tight gas sandstones, and which was presented at the American Association of Geologists Annual Meeting, was awarded the AAPG Energy Minerals Division President's Certificate for Excellence in Presentation. Finally, a paper titled *Fracture Detection in Low-Permeability Reservoir Sandstone: A Comparison of BHTV and FMS Logs to Core,* presented at the 1988 Society of Petroleum Engineers Annual Technical Conference in Houston, October 2–5, 1988, was chosen for presentation in the Best of SPE for AAPG session at the 1989 Annual Meeting of the American Association of Petroleum Geologists.

IMPACT OF GEOLOGICAL STUDIES ON EFFICIENT NATURAL GAS PRODUCTION

This research directly benefits gas producers because collecting and assimilating information could lead to improved gas recovery and lowered completion costs through better field-development and well-completion programs in tight gas sandstones. Within the Tight Gas Sands Program, new geologic information has supported testing and applying new technologies for resource exploitation. Geologic studies in low-permeability sandstone reservoirs help industry utilize an underdeveloped gas resource at the lowest cost. A major gas resource is known to exist in stratigraphically and diagenetically complex low-permeability sandstones. By studying these sandstones as genetic units deposited in a given depositional environment, workers can transfer geologic and engineering knowledge from this system to similar systems elsewhere. Natural fractures, commonly an unknown quantity in formation evaluation, can be better understood and predicted in the context of their relationship to other, more readily measured geologic factors. More efficient exploration and development on the part of industry and lower costs for the consumer result.

The refinement of knowledge of depositional systems, reservoir geology, and structural geology can increase efficient resource utilization, benefiting both industry and the consumer. For example, a recent analysis by W. L. Fisher of reserve additions in East Texas tight gas sandstone trends (Railroad Commission of Texas Districts 5 and 6) indicates that at an in-ground value of $0.65/Mcf, as proved reserves increased nearly threefold in a decade, $5-billion-worth of reserve additions have been realized. Reserves per completion increased about 80 percent in this time. If as little as 10 percent of these reserve additions can be attributed to improved access through research and development, a conservative value, then a return of $500 million has been realized. Attributing 50 percent of this to geologic characterization of reservoirs as the foundation for applying engineering and well-log analysis, then $250 million worth of resources have been converted to reserves. Even if the geologic contribution is as low as 30 percent (arguably well below its actual contribution) the value realized is $150 million. Given GRI's expenditure on low-permeability sandstone geology research over a decade at the Bureau, which includes research on areas outside of East Texas, plus assuming an expenditure of half that amount elsewhere relating to East Texas geology, the return on research investment is between 15:1 and 25:1. Although problems pertaining to the geology and characterization of complex, low-permeability reservoirs remain, focused research on those in East Texas has had a tangible effect on efficient resource use.

The Bureau of Economic Geology has enjoyed a unique position as research organization and public agency, with a long history of providing research products to natural gas producers. Many producers look specifically to the Bureau to supply research results whether or not those producers have internal research capabilities. Such capabilities have always largely been limited to major companies, but today capabilities are shrinking even within the majors. The Bureau has increased levels of technology transfer through workshops sponsored by producers, such as those organized by the Texas Independent Producers and Royalty Owners (TIPRO). A recent (1992–93) round of TIPRO-Bureau-sponsored seminars incorporated formation evaluation and reservoir engineering of tight gas sandstone in the Travis Peak Formation and Cotton Valley Sandstone.

The Bureau has been widely recognized for its GRI-supported work on the geology of tight gas sandstones through the activities documented here. Such recognition reflects both the usefulness of the research to the producing industry and the caliber of the work.

AN ANNOTATED SUMMARY OF PROJECT PUBLICATIONS

Gas Research Institute Topical Reports

East Texas Studies

1. **Geology of the Lower Cretaceous Travis Peak Formation, East Texas—depositional history, diagenesis, structure, and reservoir engineering implications:** by Dutton, S. P., Laubach, S. E., Tye, R. S., Baumgardner, R. W., Jr., and Herrington, K. L., 1990, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-90/0090 prepared for the Gas Research Institute under contract no. 5082-211-0708, 170 p.

   This report summarizes stratigraphic, petrographic, and structural studies of the Lower Cretaceous Travis Peak Formation, a low-permeability gas sandstone in East Texas, and presents reservoir engineering implications. Depositional systems in this region were interpreted from logs and cores and include (1) a braided- to meandering-fluvial system that forms the majority of the Travis Peak section, (2) deltaic deposits interbedded with the distal part of the fluvial system, (3) paralic deposits that overlie and interfinger with the deltaic and fluvial deposits near the top of the Travis Peak, and (4) shelf deposits present at the downdip extent of the formation. Petrographic studies indicate that the sandstones are quartzarenites and subarkoses. Cementation by quartz, dolomite, ankerite, illite, chlorite, and reservoir bitumen has reduced porosity to <8 percent and permeability to <0.1 md throughout most of the formation. Structurally deeper sandstones are more intensely quartz cemented than are shallower sandstones and contain abundant, open natural fractures. Borehole breakouts and drilling-induced fractures in core can be used to predict horizontal stress directions and the direction of hydraulic fracture propagation. Hydraulic fractures propagate in directions subparallel to the east-northeast strike of the natural fractures; thus, hydraulically induced fractures may not intersect many natural fractures.

2. **Analysis of natural fractures and borehole ellipticity, Travis Peak Formation, East Texas:** by Laubach, S. E., Baumgardner, R. W., Jr., and Meador, Karen, 1987, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-87/0211 prepared for the Gas Research Institute under contract no. 5082-211-0708, 128 p.

   This report summarizes petrographic studies of natural and coring-induced fractures in 7 cores from the Travis Peak Formation, a low-permeability gas sandstone in East Texas, and also presents an analysis of fracturing and wellbore elongation based on Borehole Televiewer, Formation Microscanner, and Ellipticity logs from 12 Travis Peak wells. Natural, vertical extension fractures in sandstone are open or only partly mineral filled in the cored depth range (~-5,000 to -10,000 ft), and they are therefore potential gas reservoirs as well as a potentially important influence on commercial hydraulic fracture treatment. Crack-seal structure in fracture-filling quartz shows that fracturing and quartz cementation were contemporary; this result, together with evidence of timing of fracturing and the large water volumes that are inferred to have passed through the Travis Peak, suggests that elevated pore-fluid pressures enhanced fracture development. Healed transgranular microfractures that occur in sandstone can be used to ascertain natural fracture trends in core that lacks macrofractures, and coring-induced petal-centerline fractures can be used to infer stress orientations. Fractures trend east-northeast to east. In the upper Travis Peak, borehole ellipticity trends east-northeast, parallel to fracture trends, and in the lower

Travis Peak ellipticity trends north-northwest, parallel to the direction of least horizontal stress. This preliminary report presents initial data and conclusions that were developed in subsequent work and reported in Bureau Report of Investigations No. 185 and various journal publications.

3. **Application of borehole-imaging logs to geologic analysis, Cotton Valley Group and Travis Peak Formation, GRI Staged Field Experiment wells, East Texas:** by Laubach, S. E., Hamlin, H. S., Buehring, Robert, Baumgardner, R. W., Jr., and Monson, E. R., 1990, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-90/0222 prepared for the Gas Research Institute under contract no. 5082-211-0708, 115 p.

   This report summarizes studies of two geophysical logging tools, the borehole televiewer and the Formation Microscanner, that were used in GRI's three Staged Field Experiment wells and in a cooperative well in East Texas. These tools can detect natural fractures and induced fractures that reflect in situ stress conditions, as well as lithologic features that can be important for geologic interpretation. Improvement in borehole televiewer and Formation Microscanner technology has been rapid in the past several years, but calibration of the logs with core is needed to ensure accurate interpretations of the logs. Our study compares borehole televiewer and Formation Microscanner logs with core from wells in low-permeability gas reservoir sandstone. Vertical fractures in Travis Peak and Cotton Valley sandstone usually are visible on borehole televiewer and Formation Microscanner logs, but some fractures were missed or are indistinct. Aspects of fracture shape can be determined and fractures can generally be separated from borehole breakouts, but natural fractures are difficult to distinguish from some types of drilling-induced fractures on either log. Fracture orientation is readily obtained for inclined fractures from either borehole televiewer or Formation Microscanner logs, but the orientation of vertical fractures, the common fracture type in East Texas reservoirs, can be ambiguous locally on both logs. Formation Microscanner images can be used to help document and interpret depositional environment, and they provide images of sedimentary structures and thin beds.

4. **The Travis Peak (Hosston) Formation: geologic framework, core studies, and engineering field analysis:** by Finley, R. J., Dutton, S. P., Lin, Z. S., and Saucier, A. E., 1985, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-85/0044 prepared for the Gas Research Institute under contract no. 5082-211-0708, 233 p.

   Because this was the first Bureau topical report on the Travis Peak Formation, much of the information in it was updated and superseded in subsequent reports, particularly the regional stratigraphic interpretations (see GRI-88/0325 and GRI-90/0090).

   The Travis Peak (Hosston) Formation constitutes a 1,000- to 5,000-ft-thick clastic wedge that formed two major depocenters along the north flank of the Gulf Coast Basin. The depocenters were dominated by fluvial-deltaic facies. A delta-fringe facies, including tidal flat and nearshore shallow-marine shelf facies, formed around the margins of the clastic wedge. These marginal-marine deposits within the upper Travis Peak are the most productive facies of the formation within a nine-county area in East Texas.

   Sandstones in the Travis Peak are mineralogically mature. Low permeability and occlusion of porosity is primarily due to quartz overgrowths, authigenic clay, ankerite, and reservoir bitumen, a high-molecular-weight hydrocarbon residue. Within six Travis Peak gas fields in East Texas, porosity ranges from 8 to 11 percent and water saturation ranges from 28 to 44 percent within intervals of net pay. The permeability-thickness product is low in the south part of the study area and increases toward the north. Upper limits of permeability range from 0.074 md (median value) to 0.084 md (thickness-weighted average), on the basis of well tests that postdate fracture treatment. Within Chapel Hill field, three reservoir sandstone types were defined; sandstones with greatest lateral continuity were deposited as sandy tidal flats, including associated channel sandstones that trend northwest. Lower energy tidal-flat deposition is characterized by increased mud content of sandstones, and local marine transgression resulted in deposition of mudstone and muddy limestone.

5. **Diagenesis and burial history of the Lower Cretaceous Travis Peak Formation, East Texas: controls on permeability in a tight gas sandstone:** by Dutton, S. P., 1987, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-87/0079 prepared for the Gas Research Institute under contract no. 5082-211-0708, 158 p.

   Petrographic and geochemical studies were used to determine the diagenetic and burial history of Travis Peak sandstones in East Texas and to relate the diagenesis to permeability variations within the formation. Permeability in much of the formation has been reduced to less than 0.1 md by compaction, cementation, and minor pressure solution.

   Travis Peak sandstone is quartzarenite and subarkose, having an average composition of $Q_{95}F_4R_1$. The first authigenic cements to precipitate were illite, which coated detrital grains with tangentially oriented crystals, and dolomite. Next, extensive quartz cement, averaging 17 percent of the rock volume in well-sorted sandstone, occluded much of the primary porosity. Quartz is most abundant in the lower Travis Peak, in well-connected sandstone beds that were deposited in braided streams. Dissolution of orthoclase and albitization of plagioclase followed quartz cementation and occurred prior to mid-Cretaceous movement of the Sabine Uplift. Illite, chlorite, and ankerite precipitated after feldspar diagenesis. Oil migrated into Travis Peak reservoirs in the Late Cretaceous from Jurassic source rocks. Later deasphalting of the oil filled much of the remaining porosity in some zones near the top of the formation with reservoir bitumen.

6. **Petrography and diagenesis of the Travis Peak (Hosston) Formation, East Texas:** by Dutton, S. P., 1985, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-85/0220 prepared for the Gas Research Institute under contract no. 5082-211-0708, 71 p.

   This preliminary report on the diagenesis of the Travis Peak Formation presents the results of petrographic studies based on data from 10 cores. The petrographic results are used to interpret the diagenetic history of Travis Peak sandstones and to relate the diagenetic history to permeability variations within the formation. Tables of petrographic data for 187 thin sections are included in the report, as are plates of photomicrographs that display characteristic features of Travis Peak sandstones. Many of the conclusions in this report are preliminary and were modified and documented more thoroughly in the later topical report GRI-87/0079 (following).

7. **Comparative engineering field studies and gas resources of the Travis Peak Formation, East Texas Basin:** by Lin, Z. S., and Finley, R. J., 1986, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-86/0016 prepared for the Gas Research Institute under contract no. 5082-211-0708, 96 p.

   Data from eight fields producing from the Travis Peak Formation in the eastern East Texas Basin were used to define key engineering parameters for each field and to develop resource-reserve estimates. Field-average porosities range from 8 to 11 percent, and the median permeability for 191 wells is 0.088 md; field-average permeability ranges from 0.006 to 0.1 md. Gas productivity generally increases from south to north across the area studied with changes in the reservoir drive mechanism.

Gas in place in the Travis Peak of the East Texas Basin is estimated to be 19.5 Tcf, assuming 12 percent of the area of the basin is ultimately productive.

8. **Stratigraphy and depositional systems of the Lower Cretaceous Travis Peak Formation, East Texas Basin:** by Tye, R. S., 1989, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-88/0325 prepared for the Gas Research Institute under contract no. 5082-211-0708, 80 p.

   The Travis Peak Formation of the East Texas Basin was divided into five lithostratigraphic units. Formation of a fluvial-deltaic-paralic-shelf depositional systems tract was interpreted from analyses of stratigraphic and sedimentologic data that were acquired for each lithostratigraphic unit from well logs and cores. During early Travis Peak development, braided streams deposited channelbelt, floodplain, and overbank sediments in most of the study area. Downdip of the braided streams, deltas prograded to the south and southeast over a shallow, stable shelf. As braided streams migrated and enlarged, the site of deltaic deposition advanced southward and expanded to the northeast. Estuaries developed in relatively sediment-starved, embayed portions of the shoreline between centers of deltaic deposition. Seaward of the deltas, shelf sandstones accumulated through sediment-gravity processes triggered by high sediment loads and rapid deposition in the deltas.

   Shoreline transgression and development of coastal-plain and paralic environments characterize late Travis Peak evolution. Fluvial systems transported a mud-rich sediment load and assumed a sinuous-braided to meandering form. Channelbelts coursed across a coastal plain with expansive floodplains and lakes and fed a few small retrogradational deltas. Estuaries enlarged and became a dominant coastal feature as submergence of the coastal plain progressed. With continued transgression, marine limestone of the Sligo Formation onlapped the Travis Peak.

9. **Relationship between radar lineaments, geologic structure, and in situ stress in East Texas:** by Baumgardner, R. W., Jr., 1988, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-88/0094 prepared for the Gas Research Institute under contract no. 5082-211-0708, 43 p.

   Radar-based lineaments in East Texas and northwest Louisiana were studied to determine their relationship to surficial and subsurface geologic structure and to in situ stress. For all lineament data, two significant azimuths of vector sums were defined: 325° and 37°. The northwest trend has the same orientation as the mean direction of wellbore elongations in the Schuler Formation throughout the East Texas Basin. However, this trend is significantly different from the 344° orientation of wellbore elongation in the overlying Travis Peak Formation. These results suggest a complex relationship between subsurface stress and the northwest lineament trend. The northeast lineament trend does not coincide with the orientation of any known stress or regional structure and may be an artifact of radar illumination direction. Unlike a previous regional study based on smaller-scale Landsat data, no consistent correlation between surficial or subsurface structure and lineament density was discovered. However, high values of lineament density occur preferentially on outcrops of the Sparta and Weches Formations. These results suggest that either (1) most radar lineaments smaller than Landsat lineaments are manifestations of unmapped subregional or local structures or (2) most radar lineaments are surficial phenomena, unrelated either to subsurface geologic structure or to stress.

10. **Landsat-based lineament analysis, East Texas Basin, and structural history of the Sabine Uplift area, East Texas and North Louisiana:** by Baumgardner, R. W., Jr., and Jackson, M. L. W., 1987, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-87/0077 prepared for the Gas Research Institute under contract no. 5082-211-0708, 117 p.

The first half of this report documents the relationship between subsurface structure and lineaments in East Texas. More than 2,200 lineaments were mapped from 1:250,000-scale Landsat images. Vector sums of greater-than-average values of length-weighted frequency define significant peaks of lineament orientation. For all lineaments, significant peaks occur at 325° and 21°. The northwest peak parallels mean azimuth of borehole elongations in Cotton Valley sandstone wells throughout East Texas. Within the salt structure province of the East Texas Basin, lineament azimuth is not significantly different from salt structure azimuth. Lineament density delineates major fault zones.

The second part of this report describes new mapping of the stratigraphy and structure of East Texas and identifies the timing, extent, and orientation of arching episodes in the Sabine Uplift area, which is important in developing a structural history of the area. Estimation of movement on the Sabine Uplift was made from isopach maps of five Lower Cretaceous units. The isopach maps show that the Sabine Uplift was not a horst during the Late Jurassic and Early Cretaceous but part of a large basinal area. Timing and magnitude of arching episodes on the uplift in the Mid-Cretaceous and early Tertiary indicate that the Sabine Uplift may have been produced by northeast-directed tectonic events in the Mexican Cordillera.

11. **Geological analysis of the Travis Peak Formation:** by Dutton, S. P., Fracasso, M. A., Laubach, S. E., Baumgardner, R. W., Jr., and Finley, R. J., 1988, *in* CER Corporation and S. A. Holditch & Associates, compilers and eds., Advancements in Travis Peak Formation evaluation and hydraulic fracture technology: Staged Field Experiment No. 1, Waskom field, Harrison County, Texas, topical report no. GRI-88/0077, prepared for the Gas Research Institute, p. 35–62.

12. **Geological analyses of the Travis Peak Formation:** by Laubach, S. E., Tye, R. S., Dutton, S. P., and Herrington, K. L., 1989, *in* Staged Field Experiment No. 2: application of advanced geological, petrophysical, and engineering technologies to evaluate and improve gas recovery from low permeability sandstone reservoirs, Travis Peak Formation, North Appleby field, Nacogdoches County, Texas: CER Corporation and S. A. Holditch and Associates, Inc., report no. GRI-89/0140 prepared for Gas Research Institute, p. 42–90.

13. **Geological analysis of the Travis Peak Formation and Cotton Valley Sandstone:** by Dutton, S. P., Laubach, S. E., Tye, R. S., Herrington, K. L, and Diggs, T. N., 1991, *in* Staged Field Experiment No. 3: application of advanced technologies in tight gas sandstones—Travis Peak and Cotton Valley Formations, Waskom field, Harrison County, Texas: CER Corporation and S. A. Holditch & Associates, Inc., topical report no. GRI-91/0048 prepared for the Gas Research Institute under contract no. 5090-211-1940, p. 27–66.

Frontier Formation

14. **Geologic controls on reservoir properties of low-permeability sandstone, Frontier Formation, Moxa Arch, southwest Wyoming:** by Dutton, S. P., Hamlin, H. S., and Laubach, S. E., 1992, The University of Texas at Austin, Bureau of Economic Geology, topical contract report no. GRI-92/0127 prepared for the Gas Research Institute under contract no. 5082-211-0708, 199 p.

This report examines the influence of stratigraphy, diagenesis, natural fractures, and in situ stress on low-permeability, gas-bearing sandstone reservoirs of the Upper Cretaceous Frontier Formation along the Moxa Arch in the Green River Basin, southwestern Wyoming. The main stratigraphic controls on distribution and quality of

Frontier reservoirs are sandstone continuity and detrital clay content. The Frontier was deposited in a fluvial-deltaic system, in which most reservoirs lie in marine upper shoreface and fluvial channel-fill sandstone facies. The major causes of porosity loss in Frontier sandstones during burial diagenesis were mechanical and chemical compaction and cementation by calcite, quartz, and authigenic clays. Despite extensive diagenetic modification, reservoir quality is best in facies that had the highest porosity and permeability at the time of deposition. Natural fractures are sparse in Frontier core, but outcrop studies show that fractures commonly are in discrete, irregularly spaced swarms separated by domains having few fractures. Natural fracture swarms are potential high-permeability "sweet spots." Stress-direction indicators give highly scattered estimates of maximum horizontal compression direction ranging from north to east or northeast. The scatter may reflect interference of natural fractures with measurements of stress directions, as well as spatially variable stress directions and low horizontal stress anisotropy.

15. **Geological analysis of the Frontier Formation:** by Laubach, S. E., Dutton, S. P., and Hamlin, H. S., 1992, *in* CER Corporation, ed., Staged Field Experiment No. 4: application of advanced technologies in tight gas sandstones—Frontier Formation, Chimney Butte field, Sublette County, Wyoming: CER Corporation, topical report no. GRI-92/0394 prepared for the Gas Research Institute under contract no. 5091-221-2130, p. 25–90.

16. **Stratigraphy and depositional systems of the Frontier Formation and their controls on reservoir development, Moxa Arch, southwest Wyoming:** by Hamlin, H. S., 1991, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-91/0128 prepared for the Gas Research Institute under contract no. 5082-211-0708, 45 p.

    By controlling sandstone continuity and detrital clay content, depositional systems influence reservoir development in low-permeability gas-bearing sandstones of the Upper Cretaceous Frontier Formation along the Moxa Arch in the Green River Basin, southwest Wyoming. Original depositional porosity and permeability are highest in clean Frontier sandstones, which even after diagenetic modification comprise the most prolific reservoirs. The Frontier was deposited in a fluvial-deltaic system, in which most reservoirs lie in fluvial channel-fill and marine shoreface sandstone facies. The fluvial channel-fill sandstones form southeast-trending belts, which are a few miles wide, several tens of feet thick, and separated by interchannel shale and sandy shale. Within the channel belts, clean sandstone occurs as discontinuous lenses as much as 20 ft thick that are interlayered and laterally gradational with mud-clast-rich shaly sandstone. The marine shoreface facies forms a continuous northeast-thinning sheet of sandstone, 40 to 120 ft thick. Clean sandstone is best developed near the top of the shoreface facies in northeast-thinning trends 5 to 40 ft thick.

17. **Diagenetic controls on reservoir properties of low-permeability sandstone, Frontier Formation, Moxa Arch, southwest Wyoming:** by Dutton, S. P., 1991, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-91/0057 prepared for the Gas Research Institute under contract no. 5082-211-0708, 48 p.

    This report presents preliminary data and conclusions about the relationship of diagenesis to permeability in Frontier sandstones. (A later, more complete synthesis is found in topical report GRI-92/0127.) Diagenetic history influences reservoir quality in low-permeability gas-bearing sandstones of the Upper Cretaceous Frontier Formation along the Moxa Arch in the Green River Basin, southwest Wyoming. Frontier Formation sandstones are litharenites and sublitharenites. Clean sandstones contain an average of 1.6 percent primary porosity and 4.4 percent secondary porosity. Calcite, quartz, mixed-layer illite-smectite (MLIS), and illite are the most abundant cements. The relative order of occurrence of diagenetic events was

(1) mechanical compaction, (2) formation of illite and MLIS rims, (3) precipitation of quartz overgrowths, (4) calcite cementation, (5) generation of secondary porosity, and (6) intergranular pressure solution and stylolitization. Low permeability in Frontier sandstones is caused by (1) loss of porosity due to compaction, (2) occlusion of primary pores by cements, particularly calcite and quartz, and (3) lining of primary pores by fibrous illite and MLIS. Unstressed permeability to air averages 0.21 md in upper-shoreface, 0.14 md in fluvial channel-fill, and 0.08 md in lower-shoreface sandstones.

18. **Analysis of hydraulic fracture azimuth and height: Staged Field Experiment No. 4:** by Laubach, S. E., Fix, J., Kalik, A., Warpinski, N., and Hill, R., 1992, *in* Application of advanced technologies in tight gas sandstones—Frontier Formation, Chimney Butte field, Sublette County, Wyoming: CER Corporation, report no. GRI-92/0394 prepared for Gas Research Institute, p. 115–132.

Other Formations

19. **Regional geology of the low-permeability, gas-bearing Cleveland Formation, western Anadarko Basin, Texas Panhandle: lithologic and depositional facies, structure, and sequence stratigraphy:** by Hentz, T. F., 1992, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-92/0459 prepared for the Gas Research Institute under contract no. 5082-211-0708, 135 p.

The Upper Pennsylvanian (lower Missourian) Cleveland Formation produces gas from low-permeability ("tight") sandstone reservoirs in the western Anadarko Basin of the northeastern Texas Panhandle. In this six-county region, these reservoirs had produced >412 Bcf of natural gas through December 31, 1989. Because of their typically low permeability, the Cleveland sandstones require acidizing and hydraulic fracture treatment to produce gas at economic rates.

This report summarizes findings on the regional geology, depositional setting, sequence stratigraphy, and petrology of the Cleveland Formation. Investigation of this sandstone involved drilling cooperative wells. The Cleveland Formation contains an estimated 38 Tcf of gas in place.

20. **Geology of the Davis Sandstone:** by Collins, E. W., Laubach, S. E., and Dutton, S. P., 1992, *in* Investigation of the Davis Sandstone (Fort Worth Basin, Texas) as a suitable formation for the GRI hydraulic fracture test site: CER Corporation, topical report no. GRI-92/0194 prepared for the Gas Research Institute under contract no. 5091-211-2130, p. 4–12.

Reservoir Survey Reports

21. **Geologic analysis of primary and secondary tight gas sand objectives, phase A—selective investigation of six stratigraphic units; phase B—initial studies:** by Finley, R. J., Garrett, C. M., Jr., Han, J. H., Lin, Z. S., Seni, S. J., Saucier, A. E., and Tyler, Noel, 1983, The University of Texas at Austin, Bureau of Economic Geology, annual report no. GRI-84/0026 prepared for the Gas Research Institute under contract no. 5082-211-0708, 334 p.

The objective was to expand and verify interpretation of the depositional systems and other geologic and engineering characteristics of six blanket-geometry tight gas sandstones, to recommend two formations for research emphasis, and to begin initial geologic framework studies of these two formations. After investigating the geology and engineering characteristics of >30 blanket-geometry tight gas sandstones in a survey of 16 sedimentary basins, defining clastic depositional systems and using constituent facies as a method of evaluating the common features of stratigraphic units of different ages in diverse sedimentary and structural settings were emphasized. Blanket-geometry tight gas sandstones considered suitable for future research by the Gas Research Institute were found primarily within deltaic and barrier-strandplain depositional systems. Expected transferability of research results (extrapolation potential) between stratigraphic units was assessed, and more detailed study of six formations was recommended.

Of the six formations, the Frontier and the upper Almond Formations of the Greater Green River Basin, the Olmos Formation of the Maverick Basin, and the Mancos "B" Sandstone of the Piceance Basin were not recommended for further research at that time, but should be researched to test barrier, offshore bar, and deltaic facies. The Corcoran and Cozzette Sandstones of the Piceance Creek Basin and the Travis Peak Formation of the East Texas Basin and North Louisiana Salt Basin were recommended for further research, and initial studies indicate that the Corcoran and Cozzette represent a barrier-strandplain system and contain barrier, offshore bar, and associated marginal-marine facies. Detailed studies of the Corcoran–Cozzette in Shire Gulch and Plateau fields show shoreface sequences common to the lower parts of both units and bay-lagoon and deltaic facies occurring in the upper parts. The Travis Peak Formation represents a deltaic system, having a lower subdivision of progradational deltaic facies, a thick middle subdivision of braided alluvial deposits, and an upper subdivision of marginal marine deposits influenced by marine transgression. Sandstones >50 ft thick are prominent in the middle subdivision in areas on the west flank of the Sabine Uplift. The estimated gas resources associated with the Corcoran–Cozzette and the Travis Peak in Texas are 3.7 and 17.3 Tcf, respectively.

Base maps and a selected number of well logs were acquired to prepare new cross sections and maps illustrating the stratigraphic characteristics of the Corcoran–Cozzette and Travis Peak Formations. Depositional systems and constituent facies were defined from cross sections and maps in conjunction with published and unpublished information compiled earlier. No major differences were noted between results reported here and the previous GRI data compilation, but a better understanding of the genetic stratigraphy of each unit was gained. For formations included in previous studies of tight gas resources, new resource estimates for particular formations were made by separating published data that had been combined for multiple formations. A completely new resource estimate was prepared for the Travis Peak Formation. Opportunities for cooperative coring and logging with operators were evaluated within the Corcoran–Cozzette producing trend. Within the East Texas Basin, study of a six-county area of high operator activity was emphasized.

22. **Site Selection for GRI cooperative tight gas field research, volume II: geologic characteristics of selected low-permeability gas sandstones:** by Baumgardner, R. W., Jr., Tye, R. S., Laubach, S. E., Diggs, T. N., Herrington, K. L., and Dutton, S. P., 1988, The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-88/0180 prepared for the Gas Research Institute under contract no. 5082-211-0708, 225 p.

Geologic, engineering, and economic data on selected formations were compiled to provide a basis for siting the fourth Staged Field Experiment (SFE) for the Tight Gas Sands Research Program. The geologic units chosen are the Abo, Cleveland, and Frontier Formations, and the Mesaverde Group. Extrapolation potential is good for all formations except the Cleveland, whose thin deltaic package has no good analogy in other low-permeability sandstones. The Abo and Frontier have the best potential for

extrapolation to other low-permeability formations. Average thickness of reservoirs is ~250 ft in the Mesaverde and Abo, ~160 ft in the Frontier, and ~120 ft in the Cleveland. Deepest production depth varies from 4,750 ft (Abo) to 12,198 ft (Second Frontier sandstone). Estimated resource base ranges from 3 Tcf (Abo) to 86 Tcf (Mesaverde). Prestimulation production ranges from too small to measure (Cleveland, Frontier, and Mesaverde) to 314 Mcf/d (Frontier). Post-stimulation production ranges from 3 Mcf/d (Mesaverde) to 12,250 Mcf/d (Cleveland). Permeability ranges from <0.0001 md (Frontier) to 1.3 md (Frontier). Natural fractures have been shown to be significant locally in the Mesaverde, but their contribution to reservoir permeability in the other formations is not well documented.

23. **Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States:** by Dutton, S. P., Clift, S. J., Hamilton, D. S., Hamlin, H. S., Hentz, T. F., Howard, W. E., Akhter, M. S., and Laubach, S. E., 1993, The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the Gas Research Institute under contract no. 5082-211-0708.

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25. **Geologic controls on reservoir properties of low-permeability sandstone, Frontier Formation, Moxa Arch, southwest Wyoming:** by Dutton, S. P., Hamlin, H. S., and Laubach, S. E., *in review*; submitted to the Wyoming Geological Survey as a Report of Investigations.

26. **Diagenesis and burial history of the Lower Cretaceous Travis Peak Formation, East Texas:** by Dutton, S. P., 1987, The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 164, 58 p.

27. **Geologic characterization of low-permeability gas reservoirs, Travis Peak Formation, East Texas:** by Dutton, S. P., Laubach, S. E., Tye, R. S., Baumgardner, R. W., Jr., and Herrington, K. L., 1991, The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 204, 89 p.

28. **Geology and engineering characteristics of selected low-permeability gas sandstones: a national survey:** by Finley, R. J., 1984, The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 138, 220 p.

29. **Structural history and origin of the Sabine Arch, East Texas and Northwest Louisiana:** by Jackson, M. L. W., and Laubach, S. E., 1991, The University of Texas at Austin, Bureau of Economic Geology Geological Circular 91-3, 47 p.

30. **Fracture analysis of the Travis Peak Formation, western flank of the Sabine Arch, East Texas:** by Laubach, S. E., 1989, The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 185, 55 p.

In Focus—Tight Gas Sands Publications

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32. **Results of applied research in the Canyon sands, Val Verde Basin, southwest Texas:** by Hamlin, H. S., Miller, William, Peterson, Richard, and Wiltgen, Nick, 1992, In Focus—Tight Gas Sands, v. 8, no. 1, p. 1–32.

33. **Results of research in the Cleveland Formation, Anadarko Basin, North Texas:** by Hentz, T. F., Hill, R. E., Whitehead, William, 1992, In Focus—Tight Gas Sands, v. 8, no. 1, p. 33–49.

34. **Identifying key reservoir elements in low-permeability reservoir sandstones: natural fractures in the Frontier Formation, southwestern Wyoming:** by Laubach, S. E., 1992, In Focus—Tight Gas Sands, v. 8, no. 2, p. 3–11.

35. **Advancements in hydraulic fracture azimuth research, Green River Basin, Wyoming:** by Laubach, S. E., 1992, In Focus—Tight Gas Sands, v. 8, no. 2, p. 12–22.

36. **The Travis Peak/Hosston Formation of East Texas and North Louisiana—a laboratory for tight gas technology development:** by Saucier, A. E., and Finley, R. J., 1984, In Focus—Tight Gas Sands, v. 1, no. 1, p. 15–25.

37. **Geologic analysis of the Travis Peak tight gas sandstones:** by Tye, R. S., Dutton, S. P., Laubach, S. E., and Finley, R. J., 1989, In Focus—Tight Gas Sands, v. 6, no. 1, p. 63–69.

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39. **Influence of provenance and burial history on diagenesis of Lower Cretaceous Frontier Formation sandstones, Green River Basin, Wyoming:** by Dutton, S. P., *in press*, Journal of Sedimentary Petrology.

40. **History of quartz cementation in the Lower Cretaceous Travis Peak Formation, East Texas:** by Dutton, S. P., and Diggs, T. N., 1990, Journal of Sedimentary Petrology, v. 60, no. 2, p. 191–202.

41. **Evolution of porosity and permeability in the Lower Cretaceous Travis Peak Formation, East Texas:** by Dutton, S. P., and Diggs, T. N., 1992, American Association of Petroleum Geologists Bulletin, v. 76, no. 2, p. 252–269.

42. **Controls on reservoir quality in tight sandstones of the Travis Peak Formation, East Texas:** by Dutton, S. P., and Finley, R. J., 1988, SPE Formation Evaluation, v. 3, no. 1, p. 97–104.

43. **Cementation and burial history of a low-permeability quartzarenite, Lower Cretaceous Travis Peak Formation, East Texas:** by Dutton, S. P., and Land, L. S., 1988, Geological Society of America Bulletin, v. 100, no. 8, p. 1271–1282.

44. **Developments in gas reservoir research with applications to tight sandstones:** by Finley, R. J., 1985, Interstate Oil Compact Commission Committee Bulletin, v. 27, no. 1, p. 47–53.

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46. **Depositional systems and diagenesis of Travis Peak tight gas sandstone reservoirs, Sabine Uplift Area, Texas:** by Fracasso, M. A., Dutton, S. P., and Finley, R. J., 1988, SPE Formation Evaluation, v. 3, no. 1, p. 105–115.

47. **Subsurface fractures and their relationship to stress history in East Texas basin sandstone:** by Laubach, S. E., 1988, Tectonophysics, v. 156, p. 37–49.

48. **Paleostress directions from the preferred orientation of closed microfractures (fluid-inclusion planes) in sandstone, East Texas basin, U.S.A.:** by Laubach, S. E., 1989, Journal of Structural Geology, v. 11, no. 5, p. 603–611.

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56. **Geologic controls on reservoir properties of Frontier Formation low-permeability gas reservoirs, Moxa Arch, Wyoming:** Dutton, S. P., and Hamlin, H. S., 1991, Proceedings, SPE Joint Rocky Mountain Regional/Low Permeability Reservoirs Symposium, Paper SPE 21851, p. 479–488. *Paper presented* by S. P. Dutton at Joint Symposium on Low Permeability Reservoirs in Denver, Colorado, April 14–17, 1991.

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58. **Depositional, diagenetic, and structural controls on reservoir properties of low-permeability sandstone, Travis Peak Formation, East Texas:** by Dutton, S. P., Laubach, S. E., and Tye, R. S., 1991, Gulf Coast Association of Geological Societies Transactions, v. 41, p. 209–220. *Abstract in* 1991 American Association of Petroleum Geologists Bulletin, v. 75, no. 9, p. 1521. *Talk presented* by S. P. Dutton at annual meeting of Gulf Coast Association of Geological Societies AAPG in Houston, Texas, October 16–18, 1991.

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60. **Subregional stratigraphic relations, diagenesis, and reservoir quality of Travis Peak tight gas sandstones, Sabine Uplift area, Texas:** by Fracasso, M. A., Finley, R. J., and Dutton, S. P., 1986, Society of Petroleum Engineers, East Texas regional meeting, Paper SPE 14666, p. 133–142. *Talk presented* by M. A. Fracasso at Society of Petroleum Engineers East Texas regional meeting in Tyler, Texas, April 20–22, 1986.

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102. **Mapping subsurface fracture trends** (abs.): by Laubach, S. E., 1987, Eos, Transactions of the American Geophysical Union, v. 68, no. 16, p. 299. *Invited presentation* at annual spring meeting of the American Geophysical Union in Baltimore, Maryland, May 18–22, 1987, as part of a special session on Field Approaches and Measurement Techniques for Quantifying Spatial Variability in Porous Media.

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106. **Fracture swarms in low-permeability-sandstone gas reservoir rocks in New Mexico, Colorado, and Wyoming: implications for exploration and development** (abs.): by Laubach, S. E., 1991, American Association of Petroleum Geologists Bulletin, v. 75, no. 6,

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110. **Opportunities for horizontal drilling in fractured low-permeability sandstones** (abs.): by Laubach, S. E., and Marin, B. A., 1992, Proceedings, Horizontal Drilling Symposium, domestic and international case studies, Rocky Mountain Association of Geologists, Denver, Colorado, October 18–21, 1992, unpaginated. *Talk presented* at RMAG Horizontal Drilling Symposium, 1992.

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112. **Fracture-trace maps of upper Pictured Cliffs Sandstone pavements, San Juan Basin, Colorado** (abs.): by Laubach, S. E., Tremain, C. M., Whitehead, N. H., III, and Baumgardner, R. W., Jr., 1990, Geological Society of America Abstracts with Programs, v. 22, no. 7, p. A202. *Talk presented* by S. E. Laubach at GSA national meeting, Dallas, Texas, 1990.

113. **Fluvial sandstone reservoirs of the Travis Peak (Hosston) Formation, East Texas Basin** (abs.): by Tye, R. S., 1989, American Association of Petroleum Geologists Bulletin, v. 73, no. 3, p. 421. *Talk presented* at AAPG annual meeting in San Antonio, Texas, April 23–26, 1989.

Oral Presentations—No Published Paper or Abstract

Listed Alphabetically by Presenter

R. W. Baumgardner, Jr.

"Lineament analysis, a supplement to subsurface fracture studies: Landsat and radar study of East Texas and Midland Basin": presented to visiting geologists involved in a project to drill and fracture horizontal wells in tight gas sandstone, Bureau of Economic Geology, Austin, Texas, 1987.

"Lineament analysis, a supplement to subsurface fracture studies: Landsat and radar study of East Texas": presented to the Geographic Information Systems and Remote Sensing Symposium, Texas Natural Resources Information System, Austin, Texas, 1987.

S. J. Clift

"Advancements in sandstone analysis through axial point-load testing": presented to the Bureau of Economic Geology Seminar, Austin, Texas, 1992.

S. P. Dutton

"Diagenesis of Travis Peak sandstones": presented to the Bureau of Economic Geology Seminar, Austin, Texas, 1985.

Core and poster display on Tight Gas Sandstone Project: presented to the Society of Petroleum Engineers, East Texas regional meeting, Tyler, Texas, 1986.

"Diagenesis and burial history of the Lower Cretaceous Travis Peak Formation, East Texas": presented to the Department of Geological Sciences, technical sessions, The University of Texas at Austin, 1986.

"Diagenesis and burial history of Travis Peak sandstones": presented to the Bureau of Economic Geology Seminar, Austin, Texas, 1986.

Results of GRI-sponsored sandstone diagenesis research presented to a delegation of scientists from the Beijing Graduate School, East China Petroleum Institute, Beijing, China PRC, at the Bureau of Economic Geology, Austin, Texas, 1986.

"Petrography and diagenesis of the Lower Cretaceous Travis Peak (Hosston) Formation, East Texas": presented to the East Texas Geological Society, Tyler, Texas, 1987.

"Petrography and diagenesis of the Lower Cretaceous Travis Peak (Hosston) Formation, East Texas": presented to Friends of the Mesozoic, Houston, Texas, 1987.

"Petrography and diagenesis of the Lower Cretaceous Travis Peak (Hosston) Formation, East Texas": presented to the Shreveport Geological Society, Shreveport, Louisiana, 1987.

"Control on permeability distribution in the Lower Cretaceous Travis Peak Formation, East Texas": presented to the Bureau of Economic Geology Seminar, Austin, Texas, 1988.

"Depositional and diagenetic controls on permeability distribution in the Lower Cretaceous Travis Peak Formation, East Texas": presented to the Department of Geological Sciences Soft Rock Seminar, The University of Texas at Austin, Austin, Texas, 1988.

"Diagenesis of the Travis Peak Formation, East Texas": presented to the Shell Oil Company Research Lab, Bellaire, Texas, 1988.

"Cementation and burial history of a low-permeability quartzarenite, Lower Cretaceous Travis Peak Formation, East Texas": presented to the Department of Geology, University of New Orleans, New Orleans, Louisiana, 1989.

"Depositional and diagenetic controls on permeability distribution in the Lower Cretaceous Travis Peak Formation, East Texas": presented to the Shreveport Chapter, Society of Professional Well Log Analysts, Shreveport, Louisiana, 1989.

"Diagenesis of Frontier tight gas sandstones": presented to the Bureau of Economic Geology Seminar, Austin, Texas, 1990.

"Integrated geological characterization of low-permeability ("tight gas") sandstone reservoirs": presented to the Forum on Improved Oil & Gas Recovery sponsored by TIPRO and the Bureau of Economic Geology, Amarillo, Texas, 1991.

"Natural gas reserves, supply, and demand: an assessment of the natural gas resource base of the United States": presented to the Commercial and Industrial Space Conditioning Alternatives Seminar, Austin, Texas, 1991.

"Influence of provenance and burial history on diagenesis of the Frontier Formation, Green River Basin, Wyoming": presented to the Bureau of Economic Geology Seminar, Austin, Texas, 1992.

"Geologic controls on reservoir properties of low-permeability sandstone, Travis Peak Formation, East Texas": presented to the Shreveport Geological Society, Shreveport, Louisiana, 1992.

R. J. Finley

"Depositional framework, reservoir character, and rock properties of the Travis Peak (Hosston) Formation, East Texas Basin": presented to the East Texas Geological Society, Tyler, Texas, 1985.

"Depositional framework, reservoir character, and rock properties of the Travis Peak (Hosston) Formation, East Texas Basin": presented to the Dallas Geological Society, Dallas, Texas, 1985.

"Depositional framework, reservoir character, and rock properties of the Travis Peak (Hosston) Formation, East Texas Basin": presented to Friends of the Mesozoic, Houston, Texas, 1985.

"Depositional framework, reservoir character, and rock properties of the Travis Peak (Hosston) Formation, East Texas Basin": presented to the Shreveport Geological Society, Shreveport, Louisiana, 1985.

"Geology and reservoir characteristics of tight gas sandstones in the Travis Peak Formation, Chapel Hill field, East Texas": presented to the Houston Geological Society, Houston, Texas, 1988.

"Tight gas sandstones": presented to the School on Fundamentals of Petroleum Engineering for employees of Schlumberger, sponsored by the Department of Petroleum Engineering, The University of Texas at Austin, 1986.

Results of GRI-sponsored research on depositional framework of the Travis Peak presented to visiting geologists involved in a project to drill and fracture horizontal wells in tight gas sandstone, Bureau of Economic Geology, Austin, Texas, 1987.

M. A. Fracasso

Results of GRI-sponsored stratigraphic research presented to a delegation of scientists from the Beijing Graduate School, East China Petroleum Institute, Beijing, China PRC, Bureau of Economic Geology, Austin, Texas, 1986.

H. S. Hamlin

"Frontier Formation stratigraphy and sandstone geometry, Green River Basin, Wyoming": presented to the Bureau of Economic Geology Seminar, Austin, Texas, 1990.

"Stratigraphy of Canyon Sandstone, Val Verde Basin": presented to the Bureau of Economic Geology Seminar, Austin, Texas, 1993.

T. F. Hentz

"Evidence for eustatic and tectonic control on the sequence stratigraphy of the Upper Pennsylvanian Cleveland Formation, western Anadarko Basin": presented to the Bureau of Economic Geology Seminar, Austin, Texas, 1992.

"Evidence for eustatic and tectonic control on the sequence stratigraphy of the Cleveland Formation, a tight gas sandstone in the western Anadarko Basin": presented to the North Texas Geological Society, Wichita Falls, Texas, 1993.

M. L. W. Jackson

Structural history of the Sabine Arch and its relation to hydrocarbon traps": presented to the East Texas Geological Society, Tyler, Texas, 1992.

Structural history of the Sabine Arch and its relation to hydrocarbon traps": presented to the Shreveport Geological Society, Shreveport, Louisiana, 1993.

S. E. Laubach

Presentations and participation in roundtable discussions at the DOSECC-Project GUIDE workshop for a proposed ultradeep continental borehole at the Balcones Research Center, The University of Texas at Austin. This meeting attracted an international audience. Talks based on GRI-sponsored research presented at this workshop were titled "Measurement of loading-induced strain in sedimentary basins" and "A suggested origin for Late Cretaceous–early Tertiary arches of the Gulf of Mexico," 1986.

Results of GRI-sponsored structural geology research presented to a delegation of scientists from the Beijing Graduate School, East China Petroleum Institute, Beijing, China PRC, at the Bureau of Economic Geology, Austin, Texas, 1986.

Results of GRI-sponsored structural geology research presented to visiting geologists involved in a project to drill and fracture horizontal wells in tight gas sandstone, Bureau of Economic Geology, Austin, Texas, 1987.

"Fractured reservoirs: lessons from the Travis Peak Formation": presented as a series of lectures to graduate class in reservoir analysis, Department of Geological Sciences, The University of Texas at Austin, 1988.

"Natural fracture history of the Travis Peak Formation": presented to the Center for Tectonophysics, Texas A&M University, 1988.

"Analysis of fractures and in situ stress in reservoir rocks": Department of Geological Sciences, The University of Texas at Austin, 1989.

"Application of borehole-imaging logs to fracture evaluation in low-permeability gas reservoirs" and "Origin, distribution, and effect on production of natural fractures in a low-permeability gas reservoir with extensive quartz cement": presented to the Society of Petroleum Engineers, Naturally Fractured Reservoir Forum, Crested Butte, Colorado, 1989.

"Aspects of geologic and geophysical evaluation of subsurface fractures": presented to Norsk Hydro a.s. Research, Bergen, Norway, 1989.

"Current research on prediction of fractures": presented to the Exxon Production Research Company, Houston, Texas, 1989.

"Analysis of in situ stress and fractures in reservoir rocks": presented to graduate reservoir geology seminar, Department of Geological Sciences, The University of Texas at Austin, 1990.

"Current views of fracture development in rock": presented to the Bureau of Economic Geology Seminar, Austin, Texas, 1991.

"Geologic aspects of fractured reservoir characterization": presented to the Forum on Improved Oil & Gas Recovery sponsored by TIPRO and the Bureau of Economic Geology, San Antonio and Longview, Texas, 1991.

"Pitfalls of fracture interpretation using borehole-imaging logs": presented to the Houston Westside Society of Professional Well Log Analysts, Houston, Texas, 1991.

"Fracture patterns in reservoir rocks": presented to the Fort Worth Geological Society, Fort Worth, Texas, 1992.

"Unraveling the relationship between fractures and diagenesis": presented to the Lawrence Berkeley National Laboratory Earth Science Division, Berkeley, California, 1992.

"Opportunities for horizontal drilling in fractured low-permeability sandstones, United States:" presented to the Horizontal Drilling Symposium, Denver, Colorado, 1992.

"Challenge: improved prediction of fracture attributes in reservoir rocks": presented to the Gas Research Institute Fracture Research Workshop, Austin, Texas, 1992.

WORKSHOPS

The Bureau of Economic Geology hosted a Fracture Research Workshop in 1987, in Austin, Texas. Bureau researchers and other contractors working on the characterization and design of fractures presented preliminary research results to an audience that included industry representatives.

Dutton, S. P., and Finley, R. J., presented "Core Workshop: Travis Peak (Hosston) Formation, East Texas" to the School on Fundamentals of Petroleum Engineering for employees of Schlumberger, sponsored by the Department of Petroleum Engineering, The University of Texas at Austin, 1986.

Dutton, S. P., and Hamlin, H. S., presented "Geology of the Frontier Formation" to the Gas Research Institute, *Tight Gas Sands Program—Frontier Formation Workshop*, Denver, Colorado, 1990.

Dutton, S. P., presented "Geology of the Travis Peak Formation and Cotton Valley Group, East Texas" to the Gas Research Institute, *East Texas Cotton Valley and Travis Peak Formations Workshops*, Tyler and Houston, Texas, 1990.

Finley, R. J., and Dutton, S. P., presented two sections of "Core workshop: Travis Peak (Hosston) Formation, East Texas" to the Shreveport Geological Society, Shreveport, Louisiana, 1985.

Hamlin, H. S., presented "Geologic overview of the Enron South Hogsback cooperative well" to the Gas Research Institute Workshop, *A Case Study of a Cooperative Well Project in the Frontier Formation, Moxa Arch, Green River Basin, Wyoming*, Denver, Colorado, 1991.

Hamlin, H. S., presented "Geology of the Canyon Sands tight gas reservoirs" to the Gas Research Institute/Society of Petroleum Engineers Workshop, *Results of Applied Research in the Canyon Sands*, Midland, Texas, 1992.

Hamlin, H. S., and Laubach, S. E., presented "Frontier Formation stratigraphy, diagenesis and natural fracturing" to the Gas Research Institute/Society of Petroleum Engineers Workshop, *Conclusions of GRI Research in the Frontier Formation*, Casper, Wyoming, 1992.

Laubach, S. E., and Hamlin, H. S., presented a field trip workshop "Fractures in the Frontier Formation" to the Rocky Mountain Sectional Meeting, American Association of Petroleum Geologists, 1992.

Laubach, S. E., presented "Structural geology of the Travis Peak Formation" to the Gas Research Institute, *Forum on Staged Field Experiment No. 1*, 1987.

Laubach, S. E., presented "Geological overview of Staged Field Experiment No. 2" to the Forum on the *Relationship between Rock Mechanical Properties and Acoustic Well Log Data*, Lakeway, Texas, May 1988.

Laubach, S. E., presented "Stratigraphy, diagenesis, and structure of the Travis Peak Formation and their effects on reservoir quality" to the Gas Research Institute, *SFE No. 2 Workshop: Techniques of Comprehensive Evaluation and Completion of Tight Gas Sands*, in association with the Gas Technology Symposium, Society of Petroleum Engineers, Dallas, Texas, 1989.

Laubach, S. E., presented "Fracture studies of sandstone, chalk, and coal" during a short course titled *Identifying and Interpreting Fractures*, sponsored by the Houston Geological Society for the Gulf Coast Association of Geological Societies Conference, Houston, Texas, 1991.

Laubach, S. E., presented "Core and outcrop observations of fracture attributes" to the Society of Exploration Geophysicists Workshop, *Geophysical Methods of Fracture Detection*, Houston, Texas, 1991.

Laubach, S. E., presented "Regional state of stress and hydraulic fracture azimuth in the western Green River Basin" to the Gas Research Institute/Society of Petroleum Engineers Workshop, *Conclusions of GRI Research in the Frontier Formation*, Casper, Wyoming, 1992.

The Bureau of Economic Geology hosted a GRI Natural Fracture Research Workshop in 1992, in Austin, Texas. Panels of experts on natural fracture research discussed current and future natural fracture research before an audience of about 70 industry representatiaves.

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