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INVESTIGATION OF THE DAVIS SANDSTONE (FT. WORTH BASIN, TEXAS) AS A SUITABLE FORMATION FOR THE GRI HYDRAULIC FRACTURE TEST SITE

S.A. Holditch & Associates
Data Well No. 1
Wise County, Texas

TOPICAL REPORT
MARCH 1992

Tight Gas Sands Project Area
CER CORPORATION
Contract No. 5091-221-2130

GAS RESEARCH INSTITUTE
8600 West Bryn Mawr Avenue
Chicago, Illinois 60631

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16. Abstract (Limit: 200 words)

The concept of the GRI Hydraulic Fracture Test Site (HFTS) was to provide a field laboratory to (1) validate 3-dimensional hydraulic fracture models in tight gas sandstone and (2) develop technology in fracture diagnostics and stimulation. The Davis sandstone in the Ft. Worth Basin, north-central Texas, was initially selected as a viable candidate formation for HFTS research based on the results of a co-op well program initiated with Dallas Production. To gather comprehensive data on a specific site for HFTS research, the S.A. Holditch & Associates Data Well No. 1 was drilled in June 1991. The results of geological, petrophysical and engineering analyses of the co-ops and data well are the basis of this report. These analyses indicate that in northern Parker and southern Wise Counties, Texas, the Davis sediments range from 250 to 350 ft thick. A broadly-continuous, 100-ft thick interval in the upper part of the gross interval comprises the Davis Reservoir. The average permeability of the Davis Reservoir was found to be 0.08 md with an average closure stress of 0.45 psi/ft. The shale barriers above and below the Davis had average closure stress of 0.63 to 0.73 psi/ft and 0.88 to 0.98 psi/ft, respectively. Hydraulic fracture azimuth was found to range from N10°E to N20°E. Drainage area from production analyses was calculated to be 48.7 acres in northwest Parker County. Natural fractures were encountered in the Davis, causing severe drilling problems in Data Well No. 1. Further work in the Davis was therefore suspended.

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Research Summary

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Contractors	Bureau of Economic Geology, University of Texas at Austin CER Corporation S.A. Holditch & Associates
Principal Investigators	E. Collins, S. Laubach, S. Dutton (BEG) G. Kukal, R. Hill (CER) B. Robinson, F. Syfan (SAH)
Objectives	The objectives of this study were to characterize the Davis Sandstone in the Ft. Worth Basin, Texas as a viable candidate formation for conducting GRI hydraulic fracture research.
Technical	The Gas Research Institute's Tight Gas Sands Perspective Program has conducted hydraulic fracture treatment research to improve the overall understanding of hydraulic fracturing in tight gas sand reservoirs since 1983. Many of the original goals of the Tight Gas Sands program have essentially been reached with regard to the methodology of defining the in-situ stresses of the various layers of rock; measuring the important parameters before, during, and after a fracture treatment; then using the information in a 3-dimensional hydraulic fracture propagation model to predict the shape and extent of the resulting hydraulic fracture. However, no methods are currently available to validate the 3-dimensional fracture models on a field scale. If a controlled field laboratory were available to conduct hydraulic fracturing research, experiments could then be designed in an attempt to validate the fracture models and develop new fracture diagnostic technology. Thus, GRI formulated a plan to construct the Hydraulic Fracture Test Site (HFTS).
Technical	The technical approach of conducting HFTS research Approach were to 1) provide a field laboratory for Proof-of-Concept tests to validate 3-dimensional hydraulic fracture propagation models in tight gas sandstones; and 2) develop technology in fracture diagnostics and stimulation to improve the ability of the industry to produce gas from tight formations. Since the intent of the GRI research program is to carry the development of new methods and techniques through the Proof-of-Concept stage, the HFTS could provide for the implementation of the final steps of a GRI-sponsored research program in 3-dimensional modeling. The test site would also be available for development and demonstration of new technology, the permanent storage of a tight gas sands data base, and a location for cooperative research partners or industry to test new ideas and concepts.

Results

The Bureau of Economic Geology (BEG) at the University of Texas identified the Davis sandstone in the Fort Worth Basin as a viable candidate for the HFTS. To learn more about the Davis sandstone, a cooperative research program was initiated with Dallas Production, Inc. Eleven wells in northwestern Parker County and southeastern Jack County, Texas were analyzed to determine the formation permeability, reservoir pressure, and vertical stress profile. In addition, cooperative research was performed on three additional wells to estimate in-situ stresses of the Davis interval using sonic logs, to obtain a geological description of the Davis from whole core analysis, and to determine natural and induced fracture azimuth.

Analyses of the cooperative research data indicated the Davis sediments in northern Parker and southern Wise Counties, Texas were about 250 to 350 ft thick. This interval is composed of about 200 ft of mudstone overlain by a broadly continuous 100 ft thick interval of interlayered sandstone and mudstone. The average permeability of the sandstone units in the Davis interval was found to be 0.08 md, with an average closure stress of 0.45 psi/ft. The shale barriers above and below the Davis sandstone yielded average closure stresses of 0.63-0.73 psi/ft and 0.88-0.98 psi/ft, respectively. Hydraulic fracture azimuth in the Davis sandstone was found to range from N10°E to N20°E, based on interpretations of borehole images of an open-hole stress test fracture.

Results of the Davis sandstone analyses appeared to conform to the site selection guidelines set forth by the HFTS Planning Committee. As such, three hundred acres located in northern Parker County and southwestern Wise County were selected as a suitable site to drill Data Well No. 1. Data Well No. 1 was intended to verify the geological and physical aspects of the Davis formation using openhole logs, oriented whole cores, open and cased-hole in-situ stress tests, and fracturing tests.

Unfortunately, while drilling Data Well No. 1 natural fractures were encountered in the top of the Davis that caused severe drilling problems.

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1.0 Executive Summary

The Gas Research Institute (GRI) Tight Gas Sands program has conducted hydraulic fracture treatment research to improve the overall understanding of hydraulic fracturing in tight gas sand reservoirs since 1983. Many of the original goals of the Tight Gas Sands program have essentially been reached with regard to the methodology of defining the in-situ stresses of the various layers of rock; measuring the important parameters before, during, and after a fracture treatment; then using the information in a 3-dimensional hydraulic fracture propagation model to predict the shape and extent of the resulting hydraulic fracture. However, no methods are currently available to validate the 3-dimensional fracture models on a field scale. If a controlled field laboratory were available to conduct hydraulic fracturing research, experiments could then be designed in an attempt to validate the fracture models and develop new fracture diagnostic technology. Thus, GRI formulated a plan to construct the Hydraulic Fracture Test Site (HFTS).

Two principal objectives of the HFTS were to 1) provide a field laboratory to validate 3-dimensional hydraulic fracture propagation models in tight gas sandstones; and 2) develop technology in fracture diagnostics and stimulation to improve the ability of the industry to produce gas from tight formations. The test site would also be available for development and demonstration of new technology, the permanent storage of a tight gas sands database, and a location for cooperative research partners or industry to test new ideas and concepts.

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Results of the Davis sandstone analyses appeared to conform to the site selection guidelines set forth by the HFTS Planning Committee. As such, 300 acres located in northern Parker County and southwestern Wise County were selected as a suitable site to drill Data Well No. 1. Data Well No. 1 was intended to verify the geological and physical aspects of the Davis

Formation using open-hole logs, oriented whole cores, open- and cased-hole in-situ stress tests, and fracturing tests.

Unfortunately, while drilling Data Well No. 1, natural fractures were encountered in the top of the Davis that caused severe drilling problems. While these drilling problems could be dealt with if this site was to be a typical producing area, they raised operational and research barriers for a field laboratory such as the HFTS. As such, further work in the Davis was suspended. The well is currently temporarily abandoned pending disposal either by plug and abandonment or sale to a bonded operator for production purposes.

This report represents the results of cooperative research conducted on several wells completed in the Davis sandstone. Detailed summaries of the data acquisition program conducted on Data Well No. 1 are also presented. In addition, a brief introduction describing the concepts and objectives of the HFTS is included in this report.

2.0 Concept and Objectives of the HFTS

The mission of the GRI Hydraulic Fracture Test Site, as originally designed, was to provide a well-characterized environment, with highly instrumented facilities and material resources, to experimentally validate methods, concepts, hypotheses and models that will improve applications of hydraulic fracturing and will expedite technology transfer for improved natural gas production. The GRI HFTS experiments were to include, but were not limited to, hydraulic fracture diagnostics, hydraulic fracture modeling, fracture fluid rheology, and fracture treatment design and control.

The HFTS has well-defined goals and objectives supporting fracture modeling and fracture diagnostic techniques. To verify the results of these techniques, the actual shape of the hydraulic fracture and the pressure distribution in that fracture would be measured. Tiltmeters, inclinometers and geophones would be used to image the created fracture from remote sensing locations. Instrumentation installed in intersecting wells would measure the pressure distribution in the fracture as well as the height, width and length.

The primary objective of the hydraulic fracturing research is to gain a better understanding of how to calculate and/or measure fracture shape and extent. The pressure distribution in a fracture is directly related to the fracture dimensions, fracture fluid viscous properties, mechanical properties of the various formation layers, and the in-situ stress distribution in the various layers. If the mechanical properties, in-situ stress properties and viscous properties of the fracture fluid could be specified with certainty, then the modeling issues surrounding these unknowns could be eliminated. However, for almost every field problem, when only a single well is involved, it is essentially impossible to know everything (in three dimensions) so that the shape and extent of the hydraulic fracture can be quantified exactly. For successful hydraulic fracture experimentation, the formation must be fully characterized in three-dimensions.

In the conceptual plan of the HFTS, plans were to concentrate research on fracture mechanics and fracture modeling. All rock layers above, below and within the hydraulically-fractured interval would be analyzed in detail. Initially, simple, linear fluids (without fracture proppants) would be used. By pumping simple fluids, a reliable and meaningful comparison between the various fracture diagnostic and 3-D modeling techniques with regard to the predicted fracture dimensions could be achieved. These techniques would then be checked for accuracy by actually measuring the shape of the fracture using the diagnostics methods and by drilling wellbores through the fracture. Additional information on the conceptual plan of the HFTS can be found in S.A. Holditch & Associates and Teledyne Geotech (1991) and Robinson and others (1992).

3.0 Results of Davis Sandstone Research and Selection of the Data Well No. 1 Location

To evaluate the suitability of the Davis Sandstone as a candidate formation for the HFTS, a number of GRI Tight Gas Sands Project Area cooperative wells were implemented to acquire key data. A portion of the data was also derived from a co-op well conducted as part of the GRI Enhanced Production from Conventional Resources Project which is evaluating the Davis as a target for horizontal drilling. The following are the key co-op wells, all operated by Dallas Production, Inc., from which data were acquired.

- Jones "D" No. 1, Parker County
- Milner No. 1, Parker County
- Kincaid No. 1, Parker County
- Rose No. 1, Parker County
- Hastings No. 1, Parker County
- Hastings No. 4, Parker County
- Jones "G" No. 1, Parker County
- Stark Smith No. 1, Parker County
- Underwood No. 1, Jack County
- Sallie Hill No. 1, Parker County
- Sallie Hill "A" No. 1, Parker County
- Gardner "B" No. 1, Jack County

The following sections address the results of geological, engineering and petrophysical analyses performed to characterize the Davis Sandstone and assess its suitability as a formation in which to conduct HFTS research.

3.1 DATA ACQUISITION AND ANALYSES IN THE DAVIS SANDSTONE

3.1.1 Geology of the Davis Sandstone

In the process of defining a specific site for HFTS research, studies were performed to determine the geologic framework of the Davis Sandstone. These studies included a definition of the regional depositional character and confirmation of facies and other key parameters through direct observation of cores from select wells. The following sections address these analyses.

Geologic Setting and Depositional Systems

The Fort Worth Basin, which contains the Davis Sandstone, is a Paleozoic foreland basin of about 20,000 mi^2 (57,000 km^2) in area that is bound on the east by the Ouachita Thrust Belt, a band of deformed Paleozoic rocks that mark the southern margin of the North American Craton (Viele, 1989) as shown in Figure 1. Northern boundaries of the basin are the Red River-Electra and Muenster Arches, the southern boundary is the Llano Uplift, and the western boundary is the Bend Arch (Thompson, 1982, 1988).

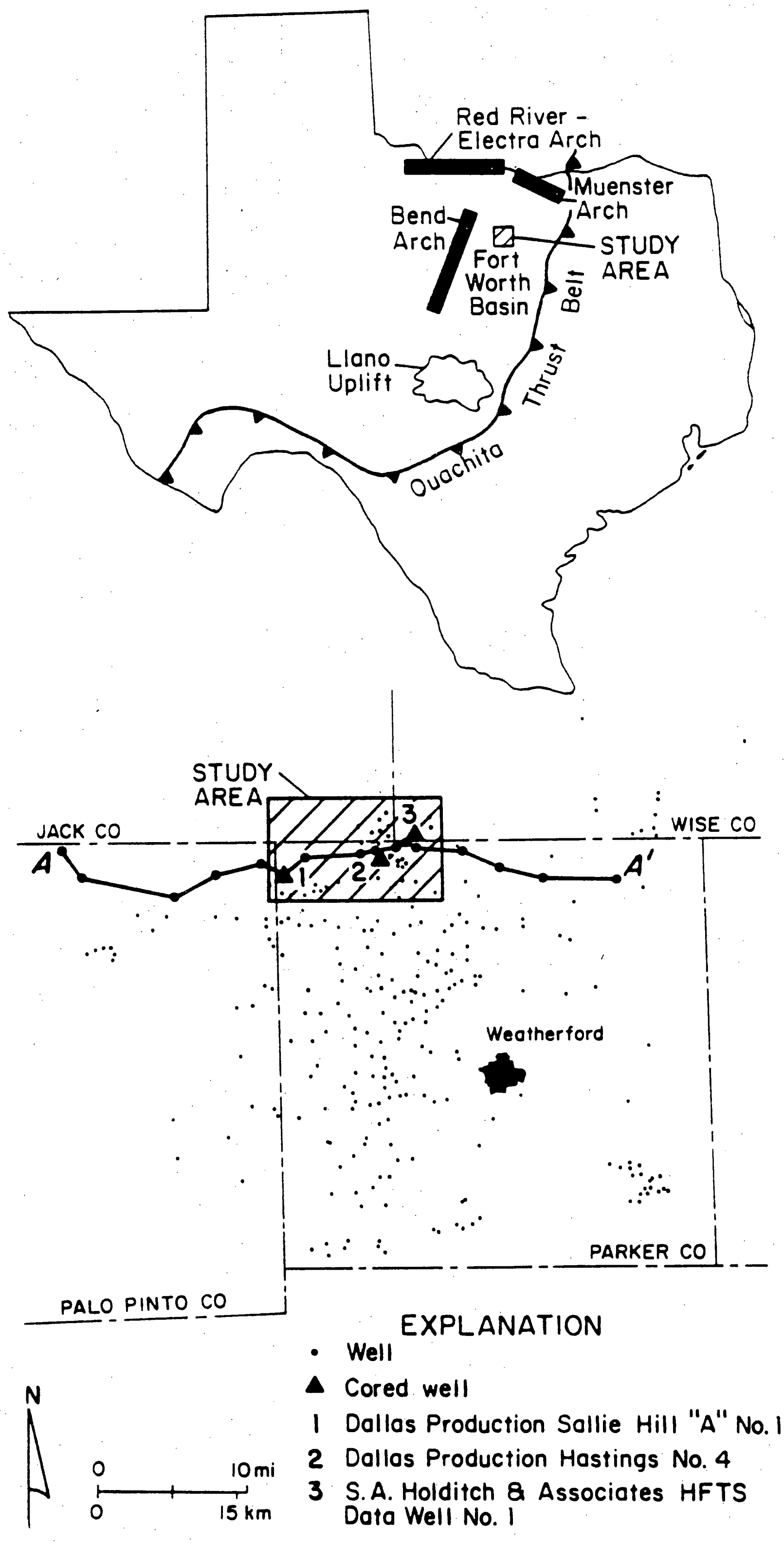


Figure 1 *Regional Setting of the Ft. Worth Basin and the Location of Key Wells in the HFTS Study Area*

As much as 13,000 ft (4,000 m) of Paleozoic rock fills the eastern part of the basin adjacent to the Ouachita Thrust Belt and Muenster Arch. The Paleozoic sedimentary package represents the transition from a passive continental margin to an actively subsiding basin (Thompson, 1988). Atokan structural movement of the Ouachita Thrust Belt and its associated foreland structures is reflected in Atokan sedimentation. The rapidly subsiding Fort Worth Basin accumulated conglomerates from the Ouachita Thrust Belt, granite wash from the Red River-Electra Arch, and comparatively minor amounts of sediments from the Muenster Arch and Llano Uplift (Thompson, 1988).

In the study area of northern Parker and southern Wise and Jack Counties, the Atokan Davis Sandstone is one of several sediment packages that appears to have prograded westward from the Ouachita Thrust Belt. The transition from the lower Atoka facies of the Big Saline and lower Grant depositional packages to the upper Atokan Davis unit represents the change from a fluvially-dominated deltaic depositional system to a wave-dominated deltaic depositional system (Thompson, 1982). The later transition from the Davis to the upper Grant, or post-Davis, marks the return of a fluvially-dominated deltaic depositional system during upper Atoka. The Davis reflects concurrent progradation and aggradation and has been interpreted by Thompson (1982) to be a system of coalesced wave-dominated deltas primarily composed of sand-rich coastal-barrier facies. These facies may consist of barrier-island beach ridges or sand ridges on a strandplain that accreted parallel to the shoreline to form a sand-rich facies having excellent strike continuity and moderately good dip continuity (Finley, 1984). Thompson (1982) reported that the Davis unit in the north Fort Worth Basin includes coastal barriers in western Parker and southern Wise Counties that resulted from wave redistribution of substantial amounts of sand along the delta margins.

In the detailed study area in northern Parker and southern Wise Counties, the Davis interval is about 250 to 350 ft (75 to 100 m) thick. The electric log pattern indicates that the interval is composed of about 200 ft (60 m) (Collins and others, 1992) of mudstone overlain by approximately 100 ft (30m) of interlayered sandstone and mudstone as shown in Figure 2. East and south of the study area, the Davis package is thicker and contains multiple stacked sandstones (Figure 2) that probably were deposited in a variety of deltaic and coastal-barrier environments. West and north, the Davis thins and contains less sandstone.

The Davis sediments probably compose a parasequence set (Van Wagoner and others, 1990) that consists of several stacked, genetically-related sediment packages or parasequences. The 100-ft thick (30-m) sandstone-rich unit in the study area consists of multiple coarsening-upward, shale to fine-grained sandstone cycles, and this unit overlies shale and siltstone facies of older Davis deltas that did not prograde as far west-northwest as the study area.

Depositional Environments Observed in Davis Sandstone Core

Core from two wells in the study area, the Sallie Hill "A" No. 1 and the Hastings No. 4, were cut from the upper sandstone-rich part of the Davis (Figure 2). Interpretations of these cores, as shown in Figure 3, indicate that the Davis sediments in the study area were deposited in prodelta, delta front and channel-mouth bar environments (Collins and others, 1992). Two 120-ft (36.5-m) cores from these two wells show that the upper sandstone-rich package of the Davis consists of multiple upward-coarsening cycles that are between 10 and 40 ft (3 and 12 m) thick (Figure 3). The cycles typically consist of shale, interbedded sandstone and shale, and relatively clean sandstone. The shale grades upward into planar and wavy-bedded

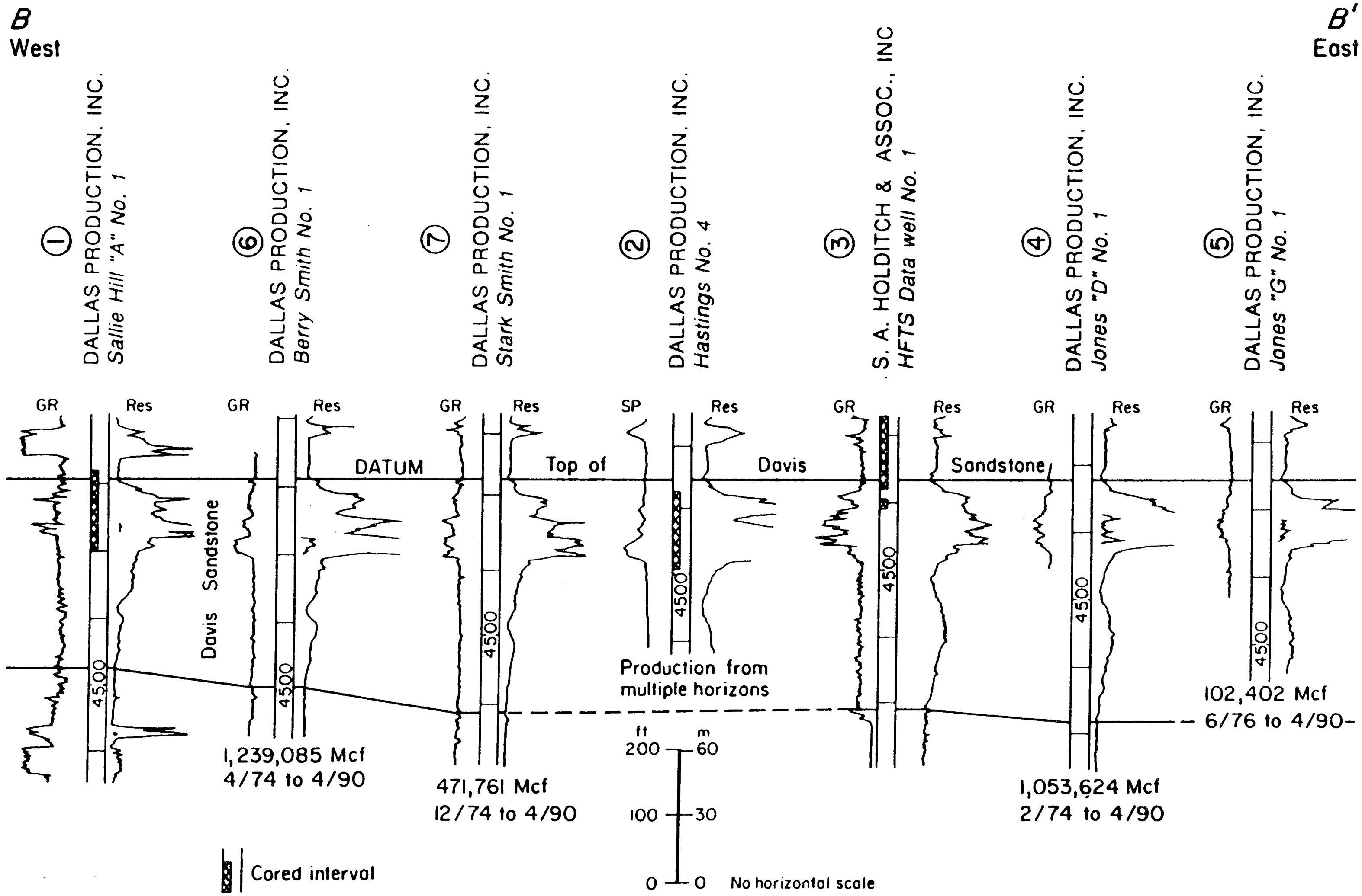


Figure 2 Cross-Section of the Davis Sandstone Across the HFTS Study Area

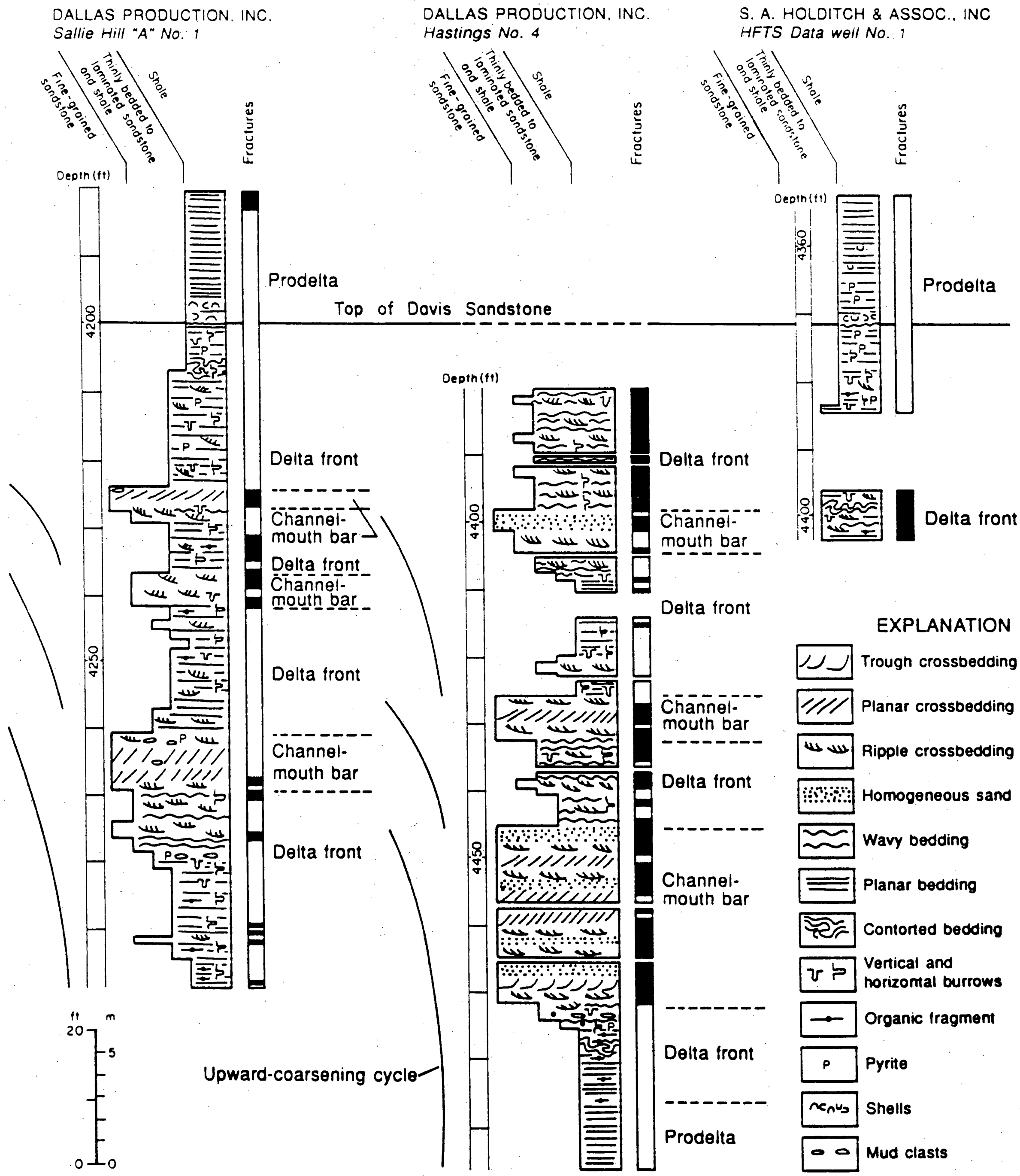


Figure 3 Core Logs from Wells Located Within the Study Area

sandstone interbedded with shale laminae and layers commonly up to an inch (several centimeters) thick. Ripple cross-laminations and vertical and horizontal burrows are also common in the laminated sandstone. The upper clean sandstone of the cycles has planar bedding, ripple cross-laminations, and planar and trough crossbedding.

The lower cycle in the Hastings No. 4 well consists of prodelta shale that grades into delta front interbedded sandstone and shale that is, in turn, overlain by channel mouth bar sandstone. Overlying cycles predominately consist of delta front deposits. Davis core from the Sallie Hill "A" No. 1 well also consists mostly of delta front deposits and contains a total of only about 20 ft (6 m) of clean sandstone, about half the amount of the Hastings No. 4 core. Davis sediments of the Sallie Hill "A" No. 1 core probably were deposited in a more distal part of the delta front than were the sediments of the Hastings No. 4 core.

The upper Davis in the Sallie Hill "A" No. 1 core grades into siltstone, and the upper contact with overlying marine mudstone is sharp. The top of the Davis is interpreted to be a marine-flooding surface. Several feet of shale directly above the contact contain abundant, reworked fossil fragments that include crinoid stems.

Davis Sandstone Composition

Petrographic results from two cores within the study area are considered broadly representative of the Davis section. From core acquired in the Hastings No. 4 and Sallie Hill "A" No. 1 wells, 33 Davis samples of sandstone, shale and interlaminated (mm to cm scale) shale and sandstone were studied. Davis Sandstone samples range from very fine to fine grained, with most samples in the very fine sandstone category (0.062 to 0.125 mm). The sorting ranges from good to poor, and most clean sandstone samples are well or moderately well sorted.

Sandstone composition can be expressed by framework grains, matrix, cements and porosity. Davis sandstones are mineralogically mature, and most are classified as sublitharenites in the sandstone classification of Folk (1974). The average composition of the essential framework grains is 84 percent quartz, 5 percent feldspar and 11 percent rock fragments. Plagioclase is the most abundant feldspar; the volume of orthoclase is less than 0.5 percent in most samples. Low-rank metamorphic rock fragments such as slate and phyllite are the most common lithic grains. Detrital organic matter constitutes up to 8 percent of the volume of mudstones and muddy sandstones.

The samples studied in thin section were selected as representing the cleanest sandstones in the Davis, with minimal detrital clay matrix. Clean sandstones should be the best reservoirs, but they are not typical of most Davis sandstones, which contain abundant shale interbeds and clay drapes along ripples. The composition of clay matrix in sandstones is impossible to identify in thin section. However, on the basis of X-ray diffraction analysis of a Davis shale sample, matrix in sandstones probably is composed of the clay minerals illite, chlorite, and kaolinite and clay-size quartz.

Cements and replacive minerals compose as much as 25 percent of the rock volume in Davis sandstones and reduce the original depositional porosity. Authigenic quartz, calcite, ankerite (iron-rich dolomite), siderite, chlorite, illite, kaolinite and pyrite have all been observed. The relative order of the major diagenetic events was (1) precipitation of chlorite flakes oriented perpendicular to detrital grains; (2) precipitation of quartz overgrowths; (3) development of secondary porosity by dissolution of feldspars; (4) precipitation of illite and kaolinite in primary and secondary pores; and (5) precipitation of pore-filling and grain-replacing Fe-calcite and ankerite.

Quartz is the most abundant cement, having volumes ranging from 8 to 16 percent in clean, well-sorted sandstones. The average volume of quartz cement in clean sandstones (<2 percent clay matrix) is 11 percent. Average volume of chlorite cement determined by thin-section point counts is 3 percent, but much of that volume is actually microporosity between chlorite crystals. Carbonate cements are not evenly distributed; most clean sandstones contain less than 2 percent carbonate cement, but a few have as much as 10 percent. Approximately half of the Fe-calcite and ankerite replaces framework grains, mainly plagioclase and orthoclase feldspar; the remainder fills intergranular pores. X-ray diffraction analysis of the clay size fraction of a clean sandstone confirmed that illite, chlorite, and kaolinite were present. Because the sample was chosen from an clean sandstone, most of the clays detected by X-ray probably are authigenic, not detrital. No expandable mixed-layer illite-smectite was detected, so swelling clays should not be a problem in Davis sandstone completions. However, iron-rich chlorite and ankerite are sensitive to acid and to oxygenated waters, so steps should be taken to minimize formation damage from completion fluids (Almon and Davies, 1978). Use of an iron sequesterant in acids will inhibit formation of pore-blocking $Fe(OH)_3$ gel (David K. Davies and Associates, Inc., 1985).

Porosity observed in thin section varies from 0 to 6 percent, and both primary and secondary pores are present. In clean sandstone, the average volume of primary porosity is 1 percent, and the average volume of secondary porosity is 0.6 percent. Most secondary pores are formed by the partial or complete dissolution of framework grains, particularly feldspars. Some secondary pores contain remnants of the original feldspar grains or reaction products such as kaolinite or illite, but many secondary pores are completely open.

Much of the original depositional porosity in Davis sandstones was lost by compaction of ductile rock fragments. Clean sandstones probably averaged 40 percent intergranular porosity when they were deposited, but intergranular porosity was reduced to about 17 percent by compaction (minus-cement porosity = 17 percent). Pore-filling cements, particularly chlorite, quartz and ankerite, then filled much of the remaining primary porosity.

Natural Fracture Abundance

Natural and drilling-induced fractures are common in both Davis cores studied from northern Parker and southern Wise Counties (Collins and others, 1992). Natural fractures were distinguished from drilling-induced fractures by the presence of vein-filling minerals in natural fractures and by surface marks and distinctive shapes (such as downward-steepening profiles of petal-centerline fractures) typical of drilling-induced fractures. The criteria used to identify drilling-induced fractures are described by Kulander and others (1990). Not all natural fractures contain infilling minerals that are readily apparent, and some induced fractures lack distinctive surface marks and shapes, so the classification of a few fractures is uncertain.

Natural fractures are vertical to subvertical extension (opening-mode) fractures. Fracture abundance in the three cores is high but variable. More than 111 natural fractures are present in the Hastings No. 4 well which is the most highly-fractured core acquired in the Davis Sandstone. Eighty percent of the sandstone core in this well contains at least one fracture.

The least fractured core, from the Sallie Hill "A" No. 1 well, has at least 21 natural fractures, 14 drilling-induced fractures, and a hydraulic fracture created during an open-hole stress test. Fracture spacing is difficult to quantify with vertical core in the Davis Sandstone because fracture dip is subparallel to the core axis, and spacing of large fractures is greater than the wellbore diameter. Centimeter-scale fractures in core are not evenly spaced. The spacing of larger fractures is therefore indeterminant. Horizontal core and outcrop fracture spacing measurements of other low-permeability sandstones show that large fractures in plan view can be arranged in irregularly-spaced clusters or swarms (Laubach, 1991). In the Davis, fractures are most common clean sandstone but also occur in interbedded sandstone and shale intervals. In the interbedded lithology, the fractures primarily occur in the sandstone-rich interbeds.

In the core studied, most natural fractures in shale overlying the Davis are small, low-angle normal faults that may be compaction features. Although opening-mode fractures are not common in shale beds in the cores described, Mississippian Barnett shale core from southeastern Wise County has vertically extensive veins (R.E. Hill, unpublished report, 1991).

Natural fractures generally end by intersecting shale interbeds or at blind terminations within sandstone. Many of the short, centimeter-tall fractures in sandstones terminate vertically against discontinuous stylolites or at blind terminations. This suggests that fractures do not form continuous networks of interconnected fractures from the top to the base of the unit. Instead, fractures tend to be confined to individual sandstones.

Fractures in Davis sandstone are typically short and vertically discontinuous. Most natural fractures have heights of 4 in. (10 cm) or less. Fracture height is generally less than bed thickness where sandstones are more than 4 in. (10 cm) thick. Short fractures within sandstone-rich layers of thinly (centimeter-sized) interbedded sandstone and shale, on the other hand, commonly have heights equal to bed thickness. In the Hastings No. 4 core, 18 fractures have heights between 4 in. and 3 ft (10 and 100 cm). Two tall fractures in thinly-interbedded sandstone and shale that are more than 3 ft (100 cm) tall are of uncertain origin. The tallest continuous fracture that is definitely natural is about 1 ft (15 cm) tall within a thick sandstone interval in the Hastings No. 4 core. Many tall fractures are composed of arrays of fractures in en echelon or relay patterns. Some of these arrays are between 1 and 2 ft (15 and 30 cm) tall. Natural fractures are generally much shorter than drilling-induced fractures in the core examined.

For most fractures, length (plan-view dimension) cannot be determined from vertical core, but evidence from small fractures suggests that fracture length is generally much greater than fracture height. This is also typical of joints in Pennsylvanian Strawn and Canyon Group rocks exposed within 30 miles (50 km) of the study area, where length-to-height ratios of more than 5:1 are common.

In core, fractures are typically narrow, commonly less than 0.25 mm wide. The widest fracture is about 1 mm. Some fractures change width abruptly along their traces, with wide segments locally occurring where fractures cross thin shale layers. Some open fractures in sandstone are small (millimeter-sized slip) faults and are closed where they cross shale interbeds. Fractures confined to sandstones have elliptical cross sections and are generally smooth-sided. Where fractures cross thin shale interbeds, the overall fracture shape is rough owing to lower fracture dips in shale beds and fracture bifurcation.

Open pore space is present along about one-third to one-half the length of some natural fractures. The apertures are generally narrow; however, many natural fractures have been broken during drilling and handling and, thus, the extent of fracture porosity and maximum fracture aperture are difficult to specify. Calcite partly fills many natural fractures. It occurs as thin 0.5 to 1 mm veneers or disseminated crystals on fracture surfaces. Gypsum (?) was detected in one fracture from the Hastings No. 4 well.

Natural Fracture Strike

Oriented core and Formation Microscanner (FMS) observations indicate that natural fractures have north-northeast strikes in the Sallie Hill "A" No. 1. Twenty-four fractures in the Sallie Hill "A" No. 1 core strike N1°W to N30°E, and three have southeast strikes. FMS logs from the same well indicate a predominant N20°E strike for fracture traces on the borehole wall. Northeast strikes in Davis core are consistent with outcrop observations of joint sets in exposed Pennsylvanian Strawn and Canyon Group rocks in this part of the Fort Worth Basin. Laubach and Hill (1990, unpublished data) measured joints in 11 stations in a 30 mi^2 (72 km^2) area near the study wells in northeastern Palo Pinto, southeastern Jack, and southwestern Wise Counties, and found that the most prominent set strikes N20°E. An outcrop study by Hoskins (1982) had similar results. In the region, an older but less well-developed joint set strikes N60°W to N80°W and a possible younger set strikes N50°W to N65°W (Laubach and Hill, unpublished data, 1990). These sets may account for some fractures in core having northwest strikes that are discordant to the predominant trend. The N50°W to N65°W set may be Cretaceous or younger in age, since this is the only set that is present in some Cretaceous outcrops in the study area (Laubach and Hill, unpublished data, 1990).

Fracture network connectivity (the degree to which fractures are in contact with one another) can have a fundamental control on the flow behavior of fluids in fracture systems. This attribute is difficult to assess with core data because only a small part of the fracture network is sampled, but core observations show that in the Davis sandstone, connectivity of small fractures is generally low. Short natural fractures in core are typically widely separated (fracture spacing is three to ten times fracture height) and are rarely observed to touch one another.

On the core scale, fractures commonly have unidirectional strike and consequently, low cross-strike network connectivity. Outcrop data, on the other hand, show that fractures with a range of strikes exist in some Pennsylvania Strawn and Canyon Group rocks in this region. If in-situ stress or vein-filling minerals have not closed or blocked these fractures in the subsurface, multiple fracture sets should increase the connectivity of the fracture network, and the size of the area in communication with a fracture in the wellbore is potentially greater.

3.1.2 Production and Reservoir Analyses

Ten wells located in the northwestern corner of Parker County and the southeastern corner of Jack County were analyzed to estimate formation permeability, the degree of stimulation (skin factor), drainage area and ultimate gas recovery. The reason for conducting this study was to determine if the Davis sandstone met the criteria established for the HFTS. Eight wells were analyzed using a production data analysis and history-matching program, PROMAT. The program uses constant-pressure, analytical solutions to the flow equations generated for different reservoir conditions. The flow equation used to analyze the data for the Davis wells was the equation for radial flow in a single-porosity, finite reservoir. In addition, the Jones "D" No. 1 and the Sallie Hill No. 1 were analyzed using a single-phase, two-dimensional, finite-difference reservoir simulator, FRACSIM. Additional details of the analyses conducted on the ten wells can be found in S. A. Holditch & Associates, Inc. (1991).

Table 1 presents the results of the production analyses. Permeability (k) ranged from 0.021 md in the Underwood No. 1 to 0.31 md for the Jones "D" No. 1. Figure 4 is an example of the history match performed on the Jones "D" No. 1 using FRACSIM. Average permeability for the ten wells was 0.08 md. Drainage area ranged from 10.3 to 122 acres. The average drainage area for the 10 wells was 48.7 acres, far less than the minimum 160-acre spacing designated for the Davis. Additional reservoir simulation work will be required for areas in northwest Parker County to determine where in-fill drilling could encounter virgin reservoir pressure.

Nine wells were found to be slightly stimulated with skin factors ranging from -0.30 in the Kincaid No. 1 to -4.9 in the Jones "D" No. 1. The relatively small negative skin factor values indicate very short effective hydraulic fracture half-lengths, if any. The slightly stimulated condition of these wellbores is probably the result of the acid balloff and small-volume fracture stimulation treatments (maximum 2 ppg sand concentrations) performed during completion operations for the Davis sandstone interval. The presence of natural fractures, which have been observed in whole cores of area wells, may also be influencing the skin factors as much as the original stimulations. The Sallie Hill No. 1, fracture stimulated with sand concentrations of 4.0 ppg, was determined to have a calculated effective fracture half-length of 140 ft.

The Sallie Hill No. 1, located in Parker County, Texas, was the only well in which a bottomhole pressure buildup survey was available. These data were analyzed using both conventional pressure buildup analysis and reservoir simulation. The Sallie Hill No. 1 was shut in for the pressure buildup (PBU) test on September 6, 1990, after producing for 25 days without interruption; the PBU test lasted for 504 hours. The PBU data were analyzed using WELLTEST, a program for performing conventional pressure transient analyses as shown in Figure 5. The buildup test data have been analyzed using pseudo-pressures (Al-Hussainy and others, 1966), pseudo-times (Agarwal, 1979) and effective pseudo-shut-in times (Agarwal, 1980a). The pseudo-pressures, pseudo-times, and pseudo-shut-in times have been converted and graphed using the adjusted pressure change according to Lee (1986) and Agarwal's equivalent time function (Agarwal, 1980b). The reservoir simulator, FRACSIM, was also used to analyze the PBU data of the Sallie Hill No. 1. The FRACSIM model is capable of including such reservoir and fracture flow phenomenon as damage around the wellbore and the fracture, non-Darcy flow, fracture permeability reduction as a function of closure pressure, formation permeability reduction with time, and wellbore storage. Since the model is capable of including these reservoir heterogeneities, FRACSIM will usually yield more accurate results than those calculated by conventional well test analysis. The reservoir and fracture properties required to obtain the PBU history match results, shown graphically in Figure 6, are presented in Table 2.

The ultimate recovery for the estimated drainage areas in the eight wells currently producing in the Davis, was found to range from 175.8 to 1,854.1 MMCF. The ultimate recovery forecasts, calculated using FRACSIM, assumed an economic limit of 15 MCFD and a constant flowing bottomhole pressure of 140 psia. An example of the production forecast for the Jones "D" No. 1 is shown in Figure 7.

Table 1 Results of Davis Sandstone Production Analyses

Well Name	Net Gas Pay, ft	Initial Reservoir Pressure, psia	Formation Gas Perm., md	Total Porosity, %	Fracture Half-Length, ft	Skin Factor	Drainage Area, acres	Cumulative Gas Produced Date	Cumulative Gas Produced MMCF	Total Producing Time, days	Forecast Ultimate Recovery, MMCF
Jones "D" No. 1	66	1,318	0.310	10.0	-	-4.90	122.0	4/90	1,054	10,670	1,854.1
Milner No. 1	45	1,477	0.055	7.5	-	-1.00	50.4	4/90	220	8,550	297.2
Kincaid No. 1	40	1,339	0.122	11.0	-	-0.30	33.7	4/90	250	6,740	307.6
Rose No. 1	45	1,222	0.071	12.0	-	-0.50	50.0	5/90	131	12,470	418.2
Hastings No. 1	62	1,338	0.152	10.0	-	-2.00	38.5	9/87[1]	470	7,820	581.4
Jones "G" No. 1	50	1,090	0.037	11.5	-	-1.50	50.0	4/90	102	8,000	175.8
Stark Smith No. 1	56	1,428	0.080	11.0	-	-3.00	40.5	4/90	472	8,770	606.0
Jones No. 2-T	54	1,343	0.081	10.0	-	-3.75	49.1	12/80	317*		
Underwood No. 1	60	1,497	0.021	10.0	-	-1.50	10.3	4/85	89*		
Sallie Hill No. 1	50	1,209	0.285	10.0	140.0	-	36.7	8/90	294	3,680	369.9

[1]Davis SS production was commingled with the Caddo Formation beginning 10/87

*Well plugged and abandoned

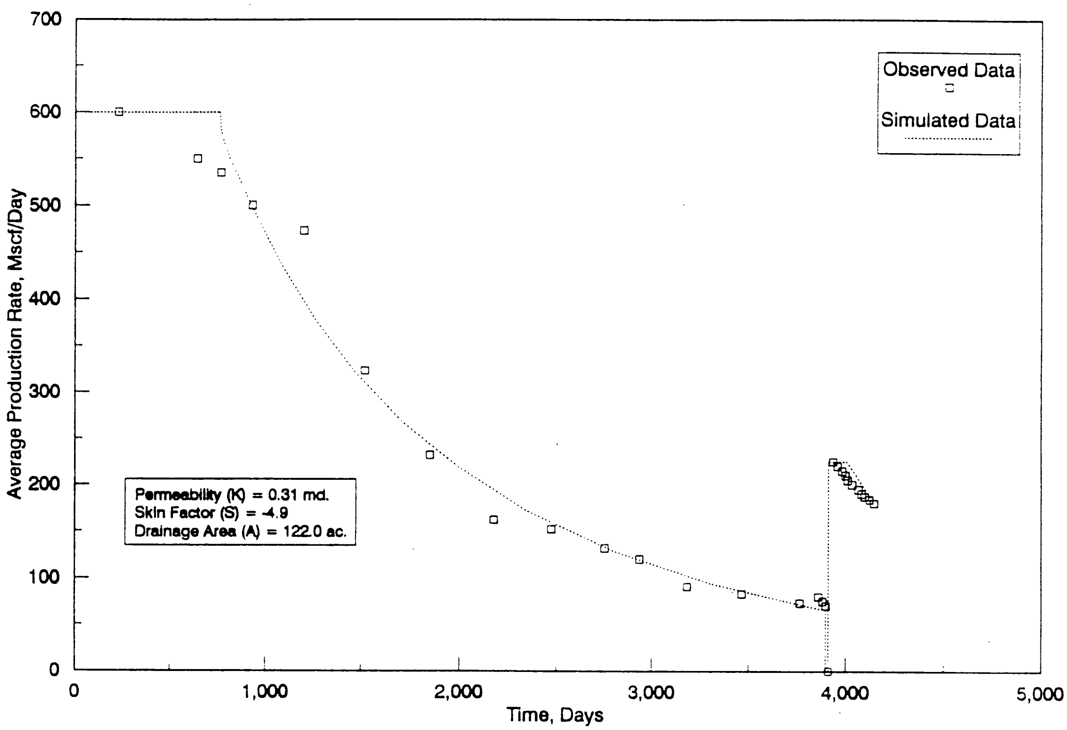


Figure 4 Jones "D" No. 1 Production History Match

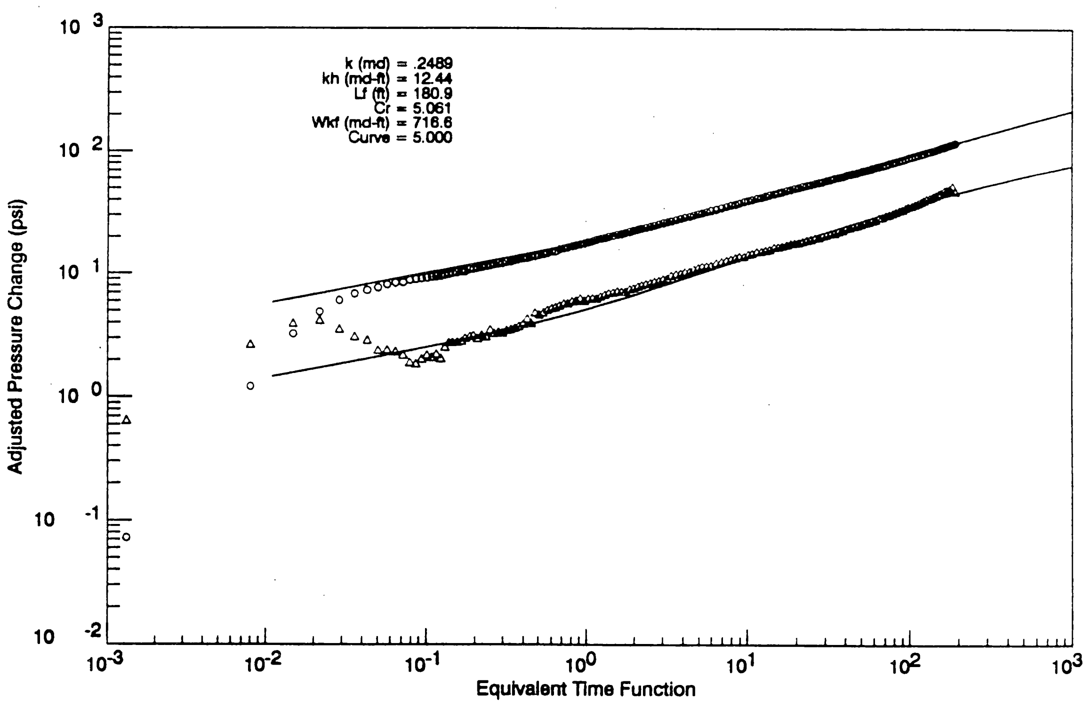


Figure 5 Sallie Hill No. 1 Type Curve Plot

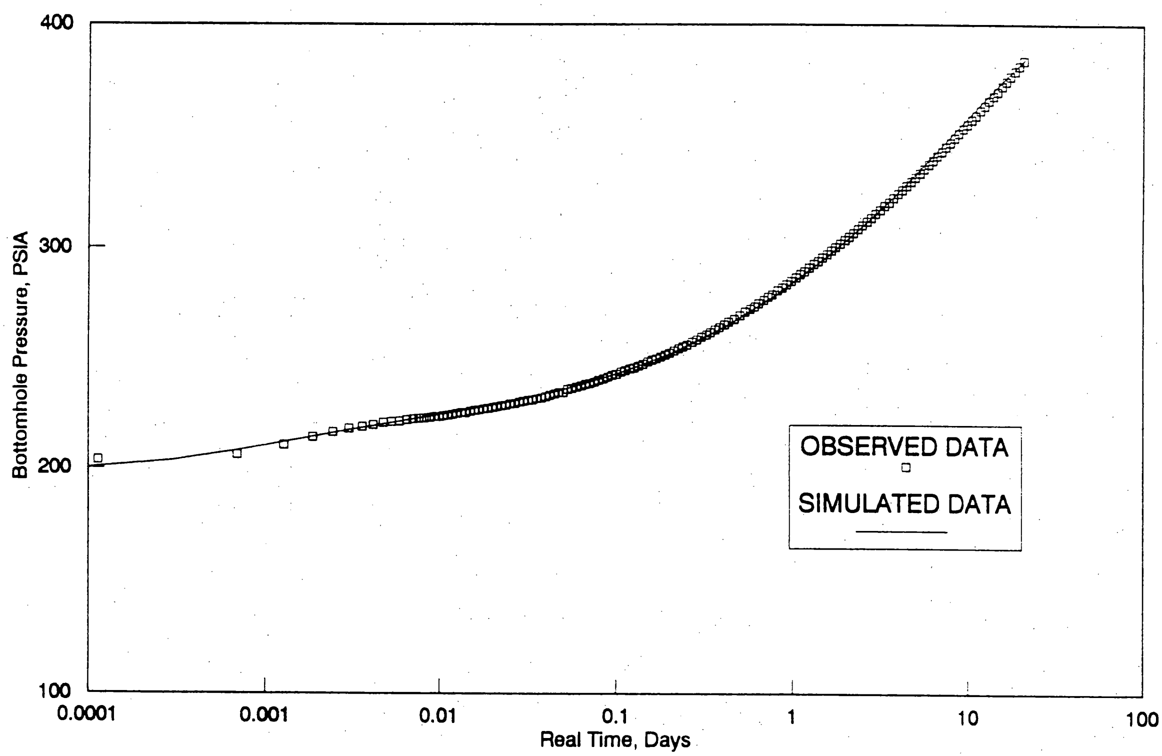


Figure 6   Sallie Hill No. 1 PBU History Match

Table 2   Sallie Hill No. 1 PBU History Match

Permeability-Thickness	14.25 md
Formation Permeability	0.285 md
Net Pay	50 ft
Fracture Half-Length	140 ft

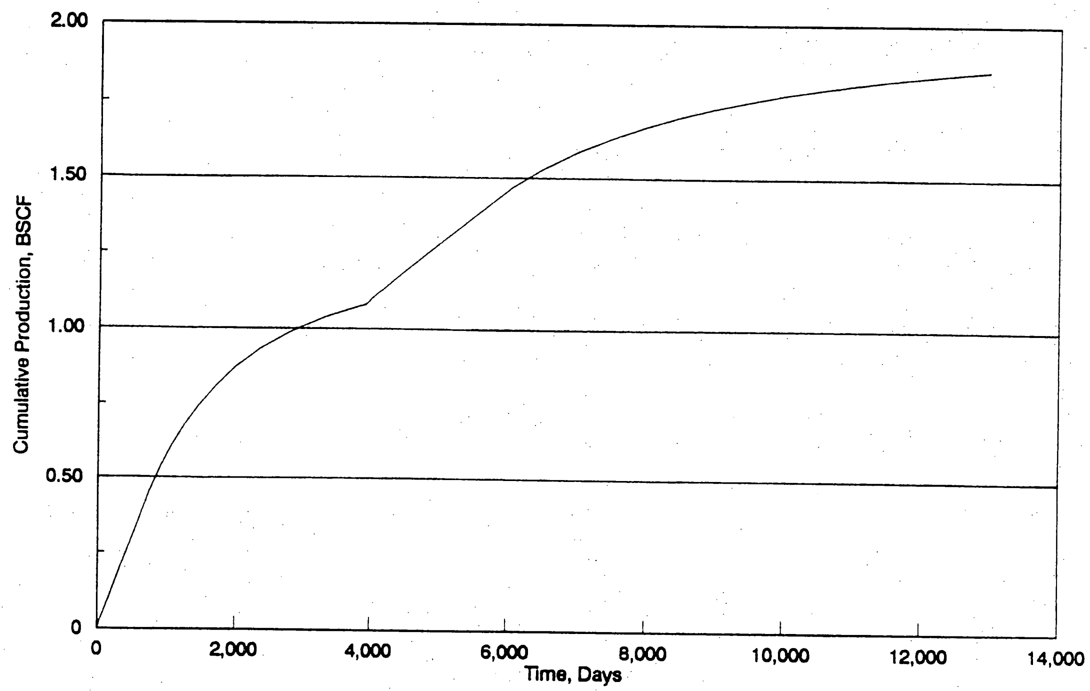


Figure 7 Jones "D" No. 1 Cumulative Production Forecast

3.1.3 In-Situ Stress Characteristics

Knowledge of the in-situ stress distribution within the reservoir sandstones and the surrounding formations is recognized as one of the most important factors in the design and analysis of a hydraulic fracture treatment. Stress contrast between various layers of rock controls the vertical fracture growth and, therefore, directly affects fracture length and width. Even though the importance of stress distribution is evident, these data are rarely measured due to the associated expense, interpretation problems and mechanical risks. Whitehead and others (1986) described the methodology involved in conducting and analyzing stress tests for the GRI project.

Before a HFTS data well could be drilled in the Davis sandstone, the in-situ closure stress of the Davis, as well as the upper and lower shales, needed to be confirmed. To evaluate this parameter, data from two co-op wells were acquired - the Gardner "B" No. 1 and the Sallie Hill "A" No. 1. Results of stress tests performed in these two wells are presented in the following sections.

Gardner "B" No. 1

The Gardner "B" No. 1 well, located in Jack County, Texas, was selected because of its proximity to an area being seriously considered for the HFTS. The well had previously produced gas from the Davis Sandstone and was temporarily abandoned when entered to perform cased-hole stress tests.

To initiate the cased-hole stress test operation, Dallas Production perforated four zones with a 3-1/8-in. casing gun over a 2-ft interval with 4 shots per foot at 120° phasing. The zones were isolated with a retrievable packer and bridge plug. A seating nipple for a downhole shut-off tool was located directly above the packer. The zones tested were as follows:

Zone	Depth, ft	Lithology
1	4,644 - 4,646	Shale
2	4,532 - 4,534	Shale
3	4,378 - 4,438	Davis Sandstone
4	4,310 - 4,312	Shale
5	4,266 - 4,268	Shale

Because the Davis sandstone had already been perforated over a 60-ft interval, a normal stress test could not be performed. Therefore, a mini-fracture treatment was pumped to measure the in-situ stress in the Davis sandstone.

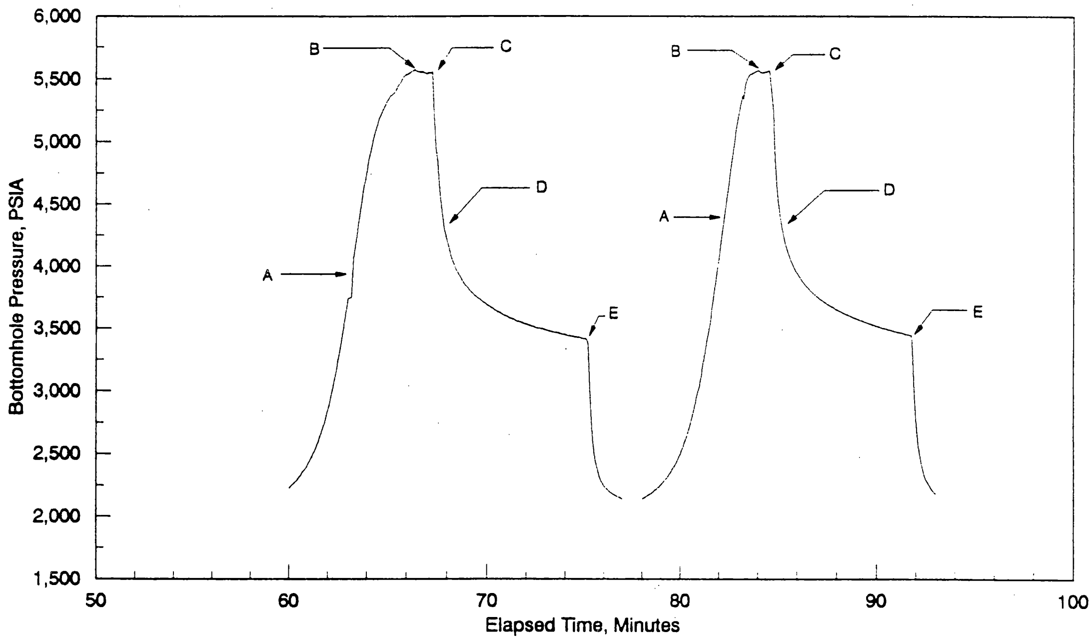
The GRI Treatment Analysis Unit (TAU) was used to monitor and record data from the in-situ stress tests. Bottomhole pressures were measured using a quartz crystal pressure gauge with surface readout. The downhole shut-off tool minimized the wellbore storage effects that tend to distort the shape of the pressure falloff curve.

During the in-situ stress tests, 2 percent KCl brine was pumped down 2-3/8-in. tubing at an injection rate of 5 to 20 gallons per minute. After injection pressures stabilized, injection into the formation was stopped by closing the downhole shut-off tool. The pressure falloff data were recorded during the shut down. Injection volume per stress test was less than 400 gallons; however, the volume of the Davis mini-fracture treatment was about 16,000 gallons.

During an in-situ stress test, the pressure decline is monitored until fracture closure is detected. At this point, the individual test stage ends. Several additional stages are pumped at the same injection rate until the results are reproduced. Figure 8 presents an example of the initial two injection/falloff stages performed on the shale at 4,532 to 4,534 ft. Seven stages were conducted on this zone.

The stress testing began with the deepest zone of interest, 4,644 to 4,646 ft. After completing the tests on this zone, the straddle packer and tubing were moved and set across the next set of perforations. The entire test procedure was then repeated on the second zone. This procedure was continued until Zones 1, 2, 4 and 5 had been tested. The final zone tested was the Davis sandstone.

Originally, only four zones were to be tested in the Gardner "B" No. 1. These were two shale tests below the Davis, a shale above the Davis at 4,266 to 4,268 ft and the Davis sandstone. With this program design, it was hoped that the in-situ stress profile for this well could be determined by testing the various lithologies. However, because the test of the zone at 4,266 ft yielded an apparent stress value much less than the apparent stresses in the shales below the Davis, the decision was made to test a fourth shale zone (4,310 to 4,312 ft) that was also above the Davis. These tests were conducted October 24 to 26, 1990. Additional tests of the Davis and the shale at 4,310 ft were conducted November 8 to 9, 1990.



A. Begin pump-in.
B. Stabilized injection rate and pressure.
C. Close downhole shut-off tool; Injection ceases.
D. Pressure falloff.
E. Surface pressure released after closure; Open downhole shut-off tool.

Figure 8 Gardner "B" No. 1 CHST 2, Perfs 4,532-4,534 ft

The tests of Zones 1 and 2 (shales below the Davis) resulted in high stress values. The analysis indicated closure pressures of 4,090 psi at 4,644 ft (0.88 psi/ft) and 4,440 psi at 4,532 ft (0.98 psi/ft). The test of Zone 5 (4,266 to 4,268 ft) yielded a closure pressure of 2,690 psi (0.63 psi/ft) which was much lower than the results in the shales below the Davis. This led to an initial suspicion that there might be a problem with cement bond behind the casing. Thus, another shale (Zone 4) above the Davis, 4,310 to 4,312 ft, was tested. This zone was actually tested on two occasions with a total of 11 individual injection stages. Closure pressure for this zone was estimated to be 3,145 psi (0.73 psi/ft).

The Davis sandstone (Zone 3) was also tested. Because 60 ft of perforations already existed and a large volume acid treatment had been pumped, a larger volume (mini-frac) treatment was necessary to determine the closure pressure of the Davis. From the step rate test which was part of the mini-fracture treatment, and the pressure falloff data, closure pressure in the Davis sandstone was estimated to be 1,980 psi (0.45 psi/ft). Table 3 summarizes the results of in-situ stress analyses from the Gardner "B" No. 1.

Sallie Hill "A" No. 1

As part of the data acquisition program for a GRI co-op well in the Enhanced Production from Conventional Resources Project Area, an open-hole stress test was performed in the Sallie Hill "A" No. 1 well, located in northwest Parker County. In this well, the open-hole stress test was performed in the upper portion of the Davis sandstone interval from 4,232 to 4,242 ft. The objectives were threefold: 1) measure the minimum in-situ stress; 2) calculate reservoir pore pressure; and 3) create a fracture suitable for azimuth determination by overcoring and imaging with wireline logs.

Table 3 Results of Cased Hole Stress Tests, Gardner "B" No. 1

Test No.	Depth, ft	Lithology	No. of Tests	Measured In-Situ Stress psia	Range, psi/ft	Avg. psi/ft
1	4,644 - 4,646	Shale	4	4,090±100	0.87 - 0.91	0.88
2	4,532 - 4,534	Shale	7	4,440±145	0.96 - 0.99	0.98
3	4,378 - 4,438	Sandstone	3	1,980±150	0.42 - 0.48	0.45
4	4,310 - 4,312	Shale	11	3,145±195	0.70 - 0.79	0.73
5	4,266 - 4,268	Shale	3	2,690±100	0.62 - 0.64	0.63

The testing process consisted of initiating and propagating a small hydraulic fracture or microfrac in a newly-cored section of the Davis sandstone. A modified version of a DST packer assembly with a 10-ft tailpipe was used to maintain pressure isolation of the test interval. The design of the OHST was similar to tests previously performed in GRI projects. Pressures were monitored and recorded during the stress tests with a surface-readout downhole pressure gauge seated into a downhole shut-in tool. Fresh water was circulated down the drillpipe to displace the drilling mud.

In all, there were six cycles of injection and shut-in. For expedience, they are indexed as Tests B1, B2, C, D, E and F. The first two attempts (B1 and B2) to break down the formation were unsuccessful. Injection on Tests B1 and B2 had to be terminated prematurely because injection pressures increased to a point which created the possibility of the packer being pumped uphole. However, on the next injection test (Test C), the formation broke down at a pressure of 2,400 psi. (All reported bottomhole pressures were corrected for 27 ft of hydrostatic head from the pressure tool to the test interval). The injection rate was about 34 gal/min. The fracture was reopened three more times (Tests D, E and F) at pressures ranging from 2,350 to 2,550 psi and injection rates of 34 to 42 gal/min. Figure 9 shows the profiles of all six tests in a composite plot of bottomhole pressure versus time.

The plot shown in Figure 9 reveals that the hydrostatic pressure measured during Tests B1 and B2 (i.e., before fracturing) was 1,840 psi, about equal to the average value of minimum horizontal stress, σ_{min} (1,855 psi). Thus, a rather unusual situation exists in which the hydrostatic head may be sufficient to reopen a previously created fracture. The fact that a stable pressure of about 1,840 psi was measured during the B2 shut-in suggests that neither B1 nor B2 initiated a fracture. In contrast, the shut-in pressures measured after the fracture was finally opened dropped well below hydrostatic.

Another feature of Figure 9 is the large pressure drop of about 650 psi experienced at shut-in. Explanations for this drop include a fracture entrance restriction, multiple parallel fractures or a large frictional pressure drop down the frac. Unfortunately, the available pumping system could not maintain constant injection rates, thereby obscuring the evaluation of frictional effects for all points except one: the shut-in. Thus, the actual fracturing pressures reported represent bottomhole wellbore pressure and not perhaps the actual pressure within the fracture during propagation.

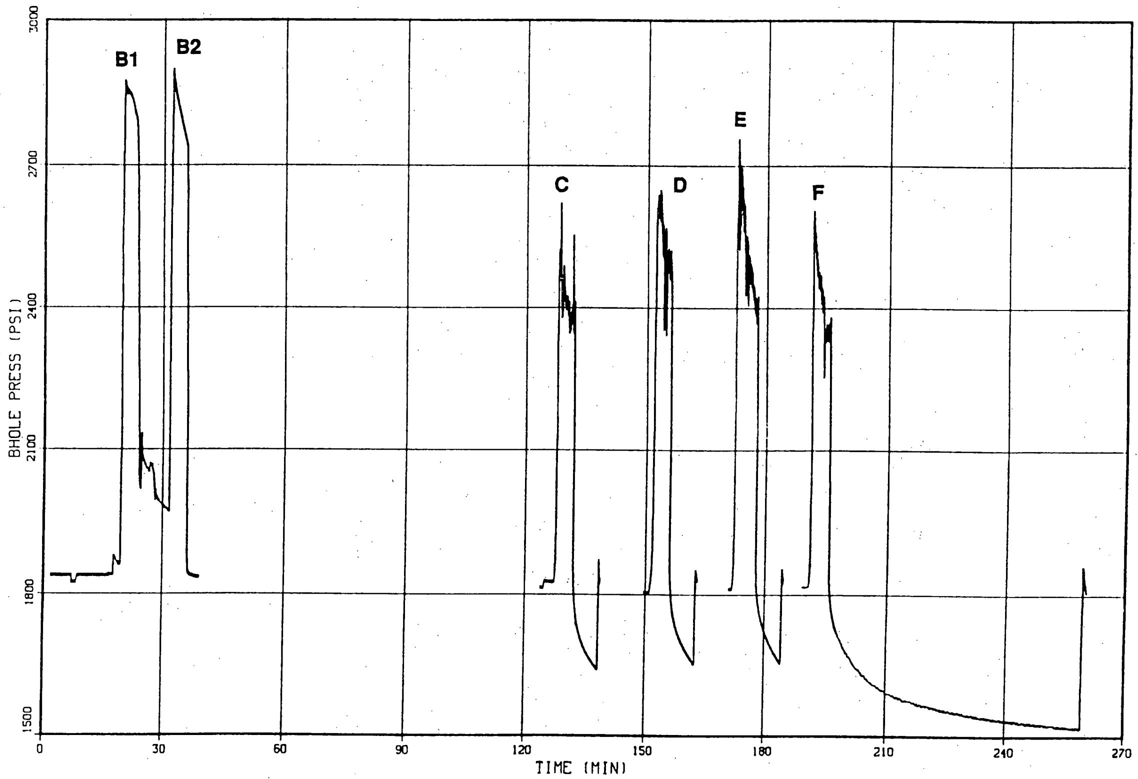


Figure 9 Sallie Hill "A" No. 1 Composite Plot of Bottomhole Pressure Vs. Time on Six OHST Injections

Test F is the longest of the six and was examined in the most detail. The pressure-time profile of this test is shown by Figure 10 while the expanded view of the shut-in is shown by Figure 11. Given the rapid leakoff, the instantaneous shut-in pressure (ISIP) of 1,850 psi probably is representative of fracture closure and thus σ_{min}.

Figure 12 is the log-log/derivative plot for Test F. On a plot of this sort, each derivative curve denotes either a radial, bilinear or linear flow regime. Dominance is assigned when the particular curve becomes flat. For Test F, a bilinear flow regime begins about 0.25 min into the shut-in. The flat line on the bilinear derivative curve also corresponds to a straight line on the plot of pressure versus 1/4 root of time given by Figure 13. This straight line occurs after about 0.7 $min^{1/4}$.

The relationship between the bilinear derivative curve and the 1/4-root-of-time curve is also found between the linear derivative curve and the 1/2-root-of-time curve. For Test F, the linear derivative curve in Figure 12 does not flatten out, indicating that linear flow never dominates. Accordingly, there are no straight line sections in the 1/2-root-of-time graph given by Figure 14.

Found during the early portions of shut-in, the presence of bilinear flow suggests that although the fracture might be closed mechanically, hydraulically it still maintains a small but finite flow capacity. Thus, the flow regime is such that fluid can flow from the wellbore, down the fracture, and into the reservoir through the newly created fracture faces.

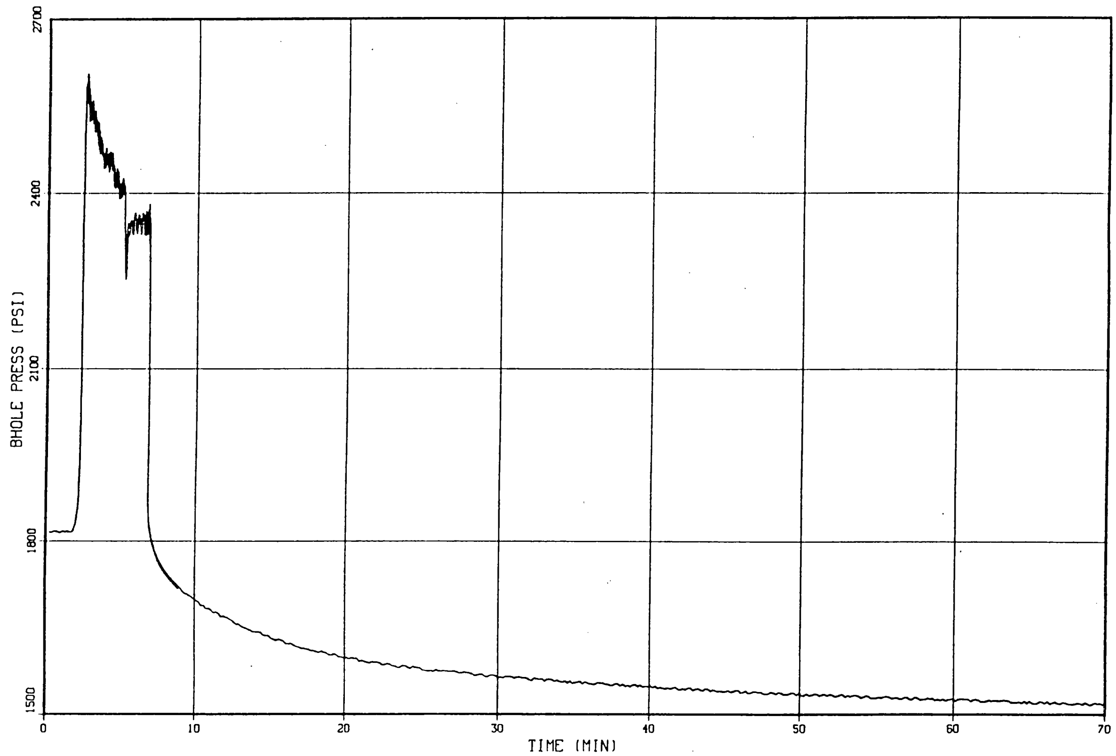


Figure 10 Sallie Hill "A" No. 1, Pressure-Time Profile of OHST Injection F

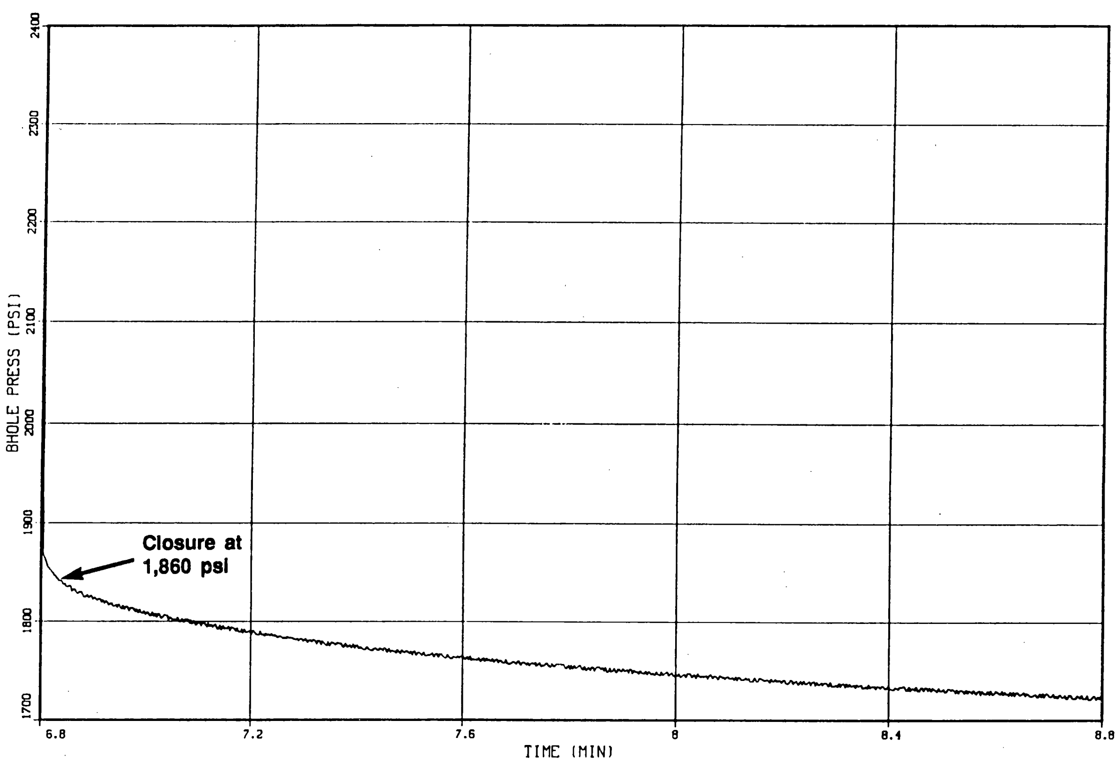


Figure 11 Expanded View of the OHST Injection F Shut-In

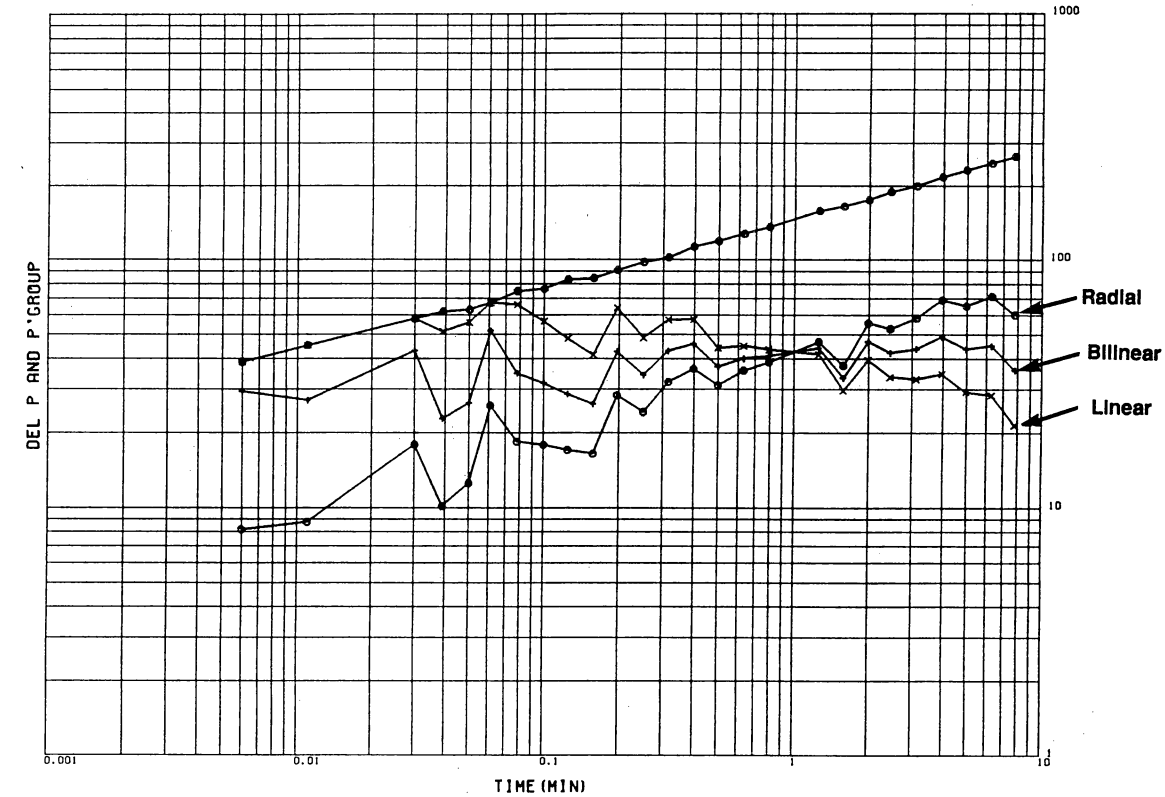


Figure 12 Log-Log Derivative Plot for OHST Injection F

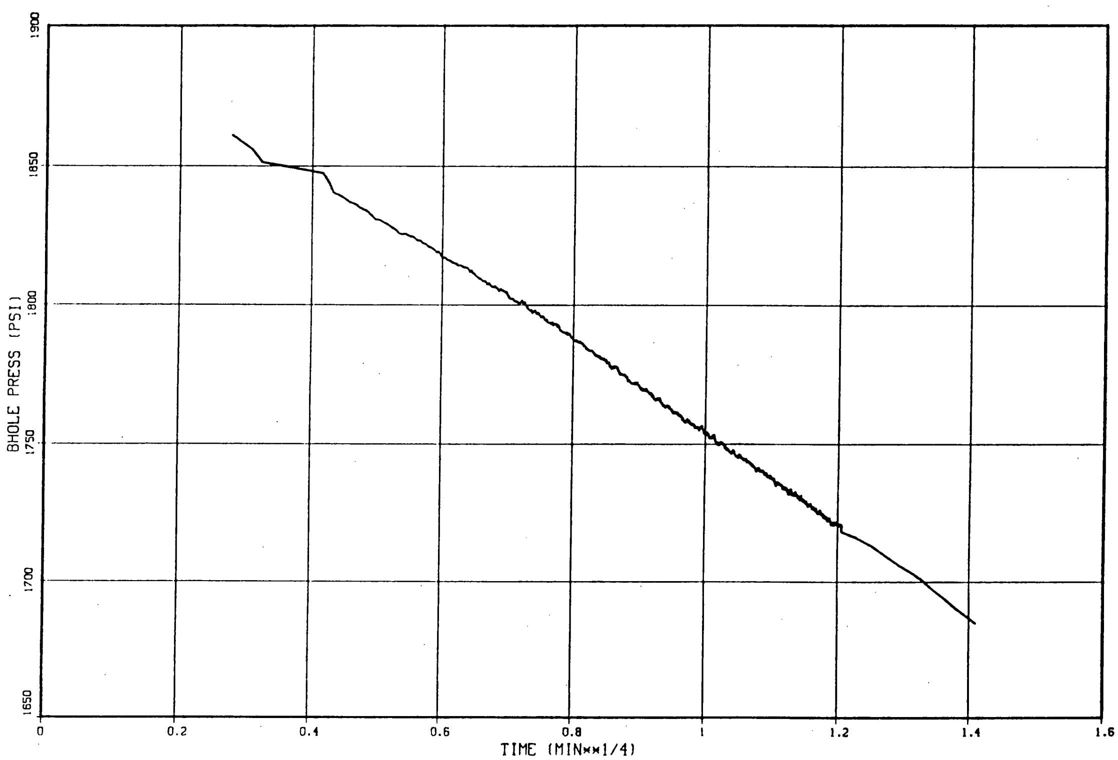


Figure 13 4th Root-of-Time Plot for OHST Injection F

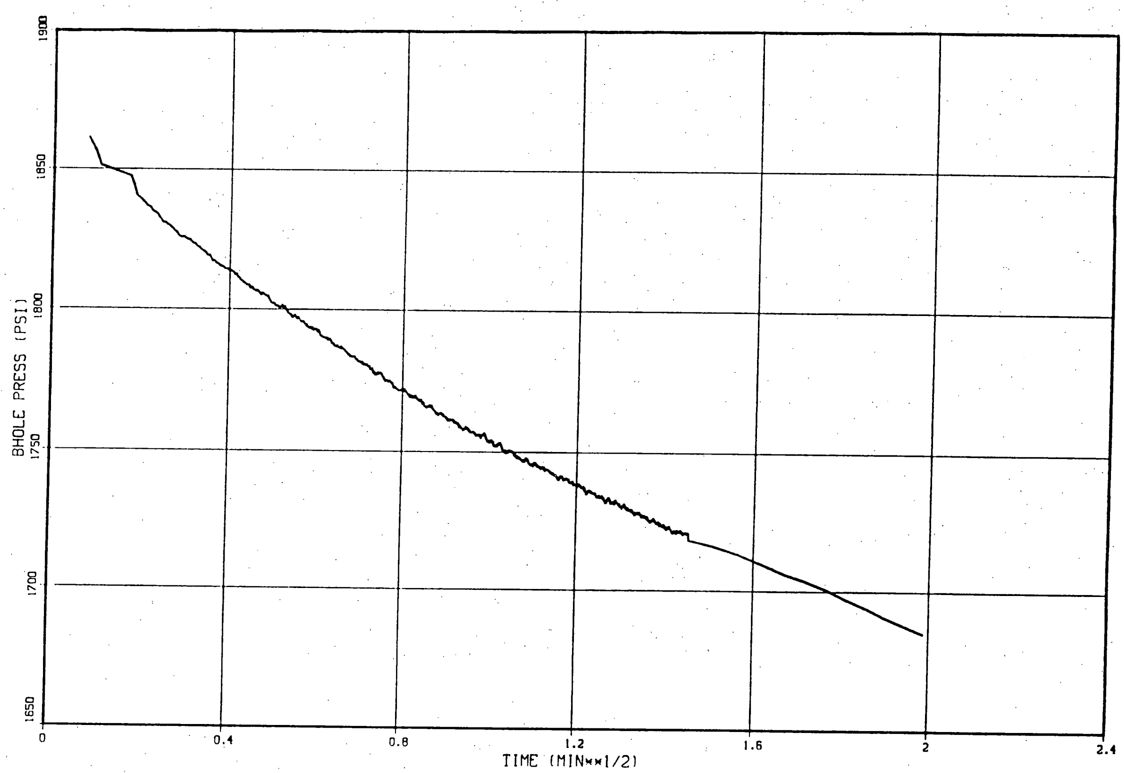


Figure 14 Square Root-of-Time Plot for OHST Injection F

To provide an estimate of pore pressure for the Davis sandstone, the shut-in for Test F was extended from the normal several minute period to almost one hour. The analysis was based on the fact that a semi-log plot of the falloff pressure exhibits a straight line once the system settles into a radial flow regime. The intercept of this line on the vertical axis is equal to the localized reservoir pore pressure. The radial derivative shown in Figure 12 starts to flatten near the end, thereby confirming the trend towards late time radial flow. The semi-log analysis of the straight line data yielded a value of 1,400 psi for pore pressure. Results of Tests B, C, D, E and F are summarized in Table 4. Detailed analyses of these tests can be found in CER Corporation (1992).

Table 4 In-Situ Stress Test Results from Davis Sandstone, Sallie Hill A No. 1

Test	P_{frac}, psi	ϕ_{min}, psi	Frac Gradient	Comments
B1	---	---	---	No apparent breakdown
B2	---	---	---	No apparent breakdown
C	2,400	1,860	0.439	Good test and shut-in
D	2,550	1,860	0.439	Good test and shut-in
E	2,400	1,850	0.437	Good test and shut-in
F	2,350	1,850	0.437	Good test; 1-hr shut-in for pore pressure

By applying the stress testing data to the generalized solution for the minimum horizontal stress, one may estimate Poisson's Ratio. The expression for σ_{min} follows:

$$\sigma_{min} = \frac{\nu}{(1-\nu)} (\sigma_v - \alpha p_o) + \alpha p_o + \sigma_{tec}$$

where
σ_{min} = minimum horizontal stress (1,855 psi)
ν = Poisson's Ratio
σ_v = overburden or vertical stress (4,236 psi)
p_o = reservoir pore pressure (1,400 psi)
α = poroelastic constant
σ_{tec} = lateral tectonic stress

Poisson's Ratio is the only unknown if one assumes that α is 1.0 and that σ_{tec} is zero (i.e., negligible). Rearranging and substituting yields

$$\nu = \frac{\dfrac{1{,}855-1{,}400}{4{,}236-1{,}400}}{1 + \dfrac{1{,}855-1{,}400}{4{,}236-1{,}400}} = 0.138$$

A Poisson's Ratio of 0.138 is rather low. If ν is set to 0.25 (a typical value), then α becomes 0.44, which is also too low. For possible explanations, one must first look to the assumptions. The poroelastic constant, α, may not be equal to 1.0; it may not even be constant. Another possibility is that σ_{tec} is not zero. The value may be negative thereby implying a tensional horizontal stress field.

3.1.4 Hydraulic Fracture Azimuth

To most effectively locate wellbores on any site selected for HFTS research, the hydraulic fracture azimuth must be known. To assess this parameter, key data were collected on the Sallie Hill "A" No. 1 cooperative well. A primary objective of this effort was to acquire a data set to predict hydraulic fracture azimuth.

The data collected on the Sallie Hill "A" No. 1 used for interpretation of hydraulic fracture azimuth included measurements of induced fractures observed in core, measurements of fractures observed in borehole image log data, over-coring and imaging an open-hole stress test fracture, measurement of borehole elongation and anelastic strain recovery core analysis (CER Corporation, 1992). Results of each of these analyses are summarized below.

Coring-Induced Fractures

Previous studies (Lorenz and Finley, 1988; Laubach and Monson, 1988) have shown that there is a definitive relationship between hydraulic fracture azimuth and azimuths of coring-induced, drilling-induced and natural fractures (if the present day and paleo-stress fields are coincident). Thus, application of this technique could result in a prediction of hydraulic fracture azimuth. The data acquired in the Sallie Hill "A" No. 1 well clearly show the N20°E to N30°E direction is the dominant orientation of both natural and induced core fractures. There is also a secondary trend of data oriented about S70°E to S80°E.

Fractures Observed In Borehole Image Log Data

In the Sallie Hill "A" No. 1, the Formation MicroScanner (FMS) borehole imagery was examined over the interval of 4,125 to 4,990 ft using the FMS Workstation in Dallas, Texas. Thirty-nine fractures were measured in the analyzed interval. Fracture characteristics suggest that they are probably drilling induced. However, because there is little angular difference between the natural and induced fractures, it is possible that some of the fractures are natural or perhaps they are drilling-enhanced natural fractures. Although the classification of fractures is uncertain, the orientation results are definitive. The vector mean of the 39 measured fractures is N8.8°E with a 95 percent confidence angle of 8.64°.

Evaluation of the Open-Hole Stress Test Fracture

The fracture induced in the Davis sandstone through the implementation of the open-hole stress test at 4,242 ft in the Sallie Hill "A" No. 1 well provided the opportunity to directly measure hydraulic fracture azimuth. The induced fracture was over-cored after the OHST, and the fractured interval was subsequently logged with the FMS borehole image log.

The OHST fracture was recovered at the top of Core No. 3 (oriented) and had a strike of N15°E and dip of 87° to the east. This orientation is in good agreement with a fracture imaged on the FMS log in the depth interval from 4,237 ft to 4,245 ft. There are no criteria to distinguish stress test fracture images from natural or drilling induced fractures; therefore, some caution is necessary in declaring this the stress test fracture. However, the orientation of the fracture on the FMS log has a strike of N9°E and dips 89° to the east.

Evaluation of Borehole Breakouts

Borehole breakouts are believed to cause a circular borehole to become elliptical in the direction parallel with the minimum horizontal stress direction. Thus, if a predominant breakout direction can be determined, a hydraulic fracture azimuth can be predicted.

In the Sallie Hill "A" No. 1 well, breakouts were analyzed using the oriented caliper data from the FMS borehole image log over the interval 5,050 to 5,308 ft. The computer model analyzes oriented calipers to detect breakouts using criteria described by Plumb and Hickman (1985) for distinguishing breakouts from other borehole elongations.

There were only seven breakouts detected. The dominant orientation of the maximum horizontal stress direction is N38°E based on six values while one value of S51°E is nearly orthogonal to the dominant set. Breakout azimuths in this well are consistently greater than the other indicators of stress azimuths (i.e., 38° from breakouts versus 20° from FMS). Because these breakouts are deeper in the well than the other data, it is not presently clear whether this represents a stress azimuth rotation with depth, or, as has been observed on other analyses, the calipers may have a slightly clockwise shift to the true breakout azimuth. This shift may result from the logging tool not rotating back into the center of the breakout as it is pulled up the borehole because there is a tendency for the tool to rotate in the clockwise direction.

Anelastic Strain Recovery Measurements

In cutting a core, and removing it from its subsurface environment, the stresses acting on that rock are relieved. If asymmetrical horizontal compressional forces exist within the formation, then the core will expand more in the direction of the greatest compression, and stress relief microfractures will form perpendicular to this expansion. Anelastic strain recovery (ASR) data are acquired by instrumenting a core sample with strain gauges as soon as possible after recovery at the surface. Subsequent processing results in an interpretation of the maximum horizontal stress azimuth.

On the Sallie Hill "A" No. 1, ASR was performed on ten Davis sandstone core samples. Six of these samples were from the same continuous section of Core No. 1, and four samples were analyzed from Core No. 2. Because of the interbedded nature of the Davis sandstone in this well, selecting suitable samples for analysis was difficult. Overall, the ASR results fell into two orientation classes which are approximately 90° apart. The two classes occur in the N40°E to N50°E range and the S40°E to S50°E range. There is a significant degree of scatter to the ASR data, and it is likely that the results were adversely affected by the complex laminated lithologies comprising the Davis sandstone. Therefore, interpretations of hydraulic fracture azimuth with ASR data were not considered to be usable.

Summary of Fracture Azimuth Results

The interpreted maximum horizontal stress direction, based primarily on interpretation of the fractures and the stress test fracture observed in the borehole image log data, is N10°E to N20°E. Figure 15 graphically shows the results of each of the data sets analyzed.

3.2 QUALIFICATIONS OF THE DAVIS SANDSTONE AS THE HFTS CANDIDATE FORMATION

Seven technical criteria (depth, thickness, permeability, pressure gradient, tectonics and gas content) were used to evaluate candidate low-permeability sandstones during the screening process. This screening defined the most desirable area for the HFTS to be in northern Parker, southern Jack and southern Wise Counties, Texas. A specific tract of land, as shown in Figure 16, was also identified as having high potential for the HFTS.

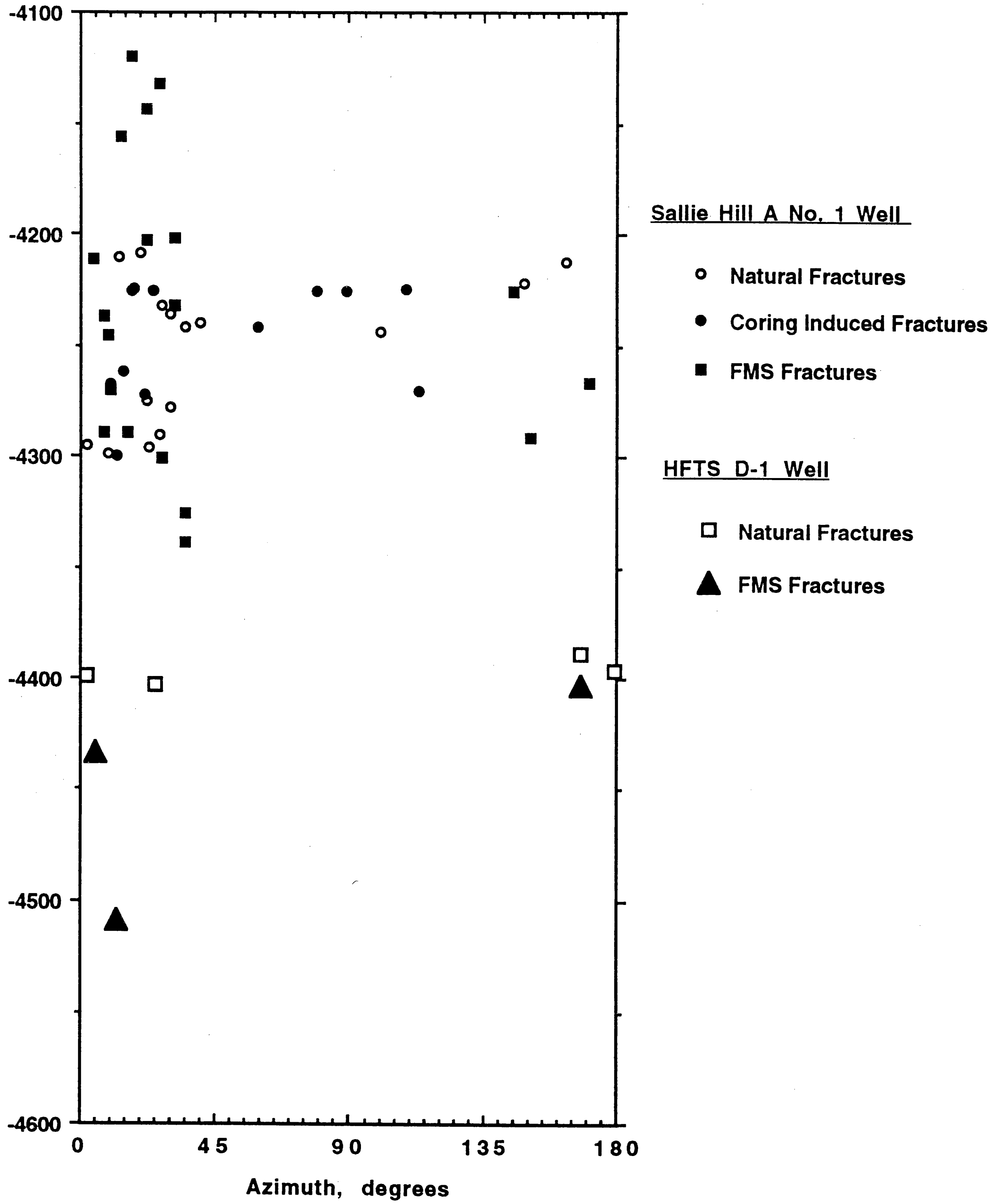


Figure 15 Results of Techniques Used to Predict Hydraulic Fracture Azimuth in the Sallie Hill "A" No. 1 Well

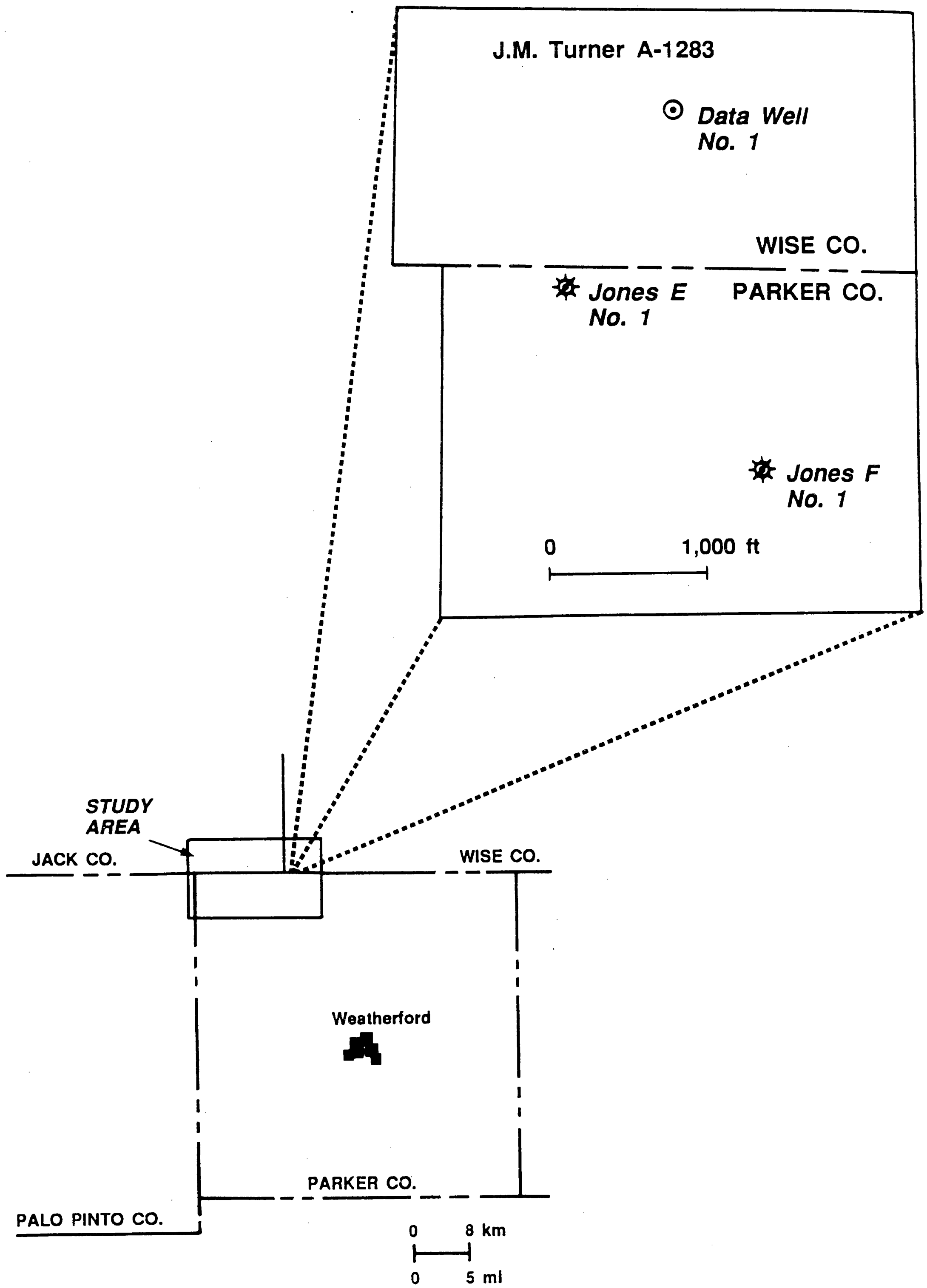


Figure 16 Area Identified as Having the Highest Potential for HFTS Research in the Davis Sandstone

4.0 Data Acquisition and Analysis of Data Well No. 1

Based upon the positive assessment of the site selection criteria, the Data Well No. 1 was located as shown in Figure 16. The following sections provide additional details relative to the actual drilling and data collection performed during the drilling phase of Data Well No. 1.

4.1 DRILLING OPERATIONS SUMMARY

Coordination and supervision of open-hole data acquisition and drilling operations on Data Well No. 1 were performed by S. A. Holditch & Associates, Inc. and CER Corporation. Drilling rig services were contracted to Bandera Drilling Corporation, and its Rig No. 5 was used to implement the drilling program. Figure 17 represents a schematic of Data Well No. 1 as originally planned. The basic phases of the drilling operation, shown graphically in Figure 18, can be summarized as follows:

1. The well was spud on June 12, 1991, and a 17-1/2-in. hole was drilled to 1,462 ft. On June 15, the hole was logged and 13-3/8-in. casing was run and cemented with 1,275 sacks of cement.

2. An 8-3/4-in. hole was then drilled from 1,462 ft to a total depth of 4,798 ft between June 15 and July 4, 1991. The top of the Davis sandstone was encountered at 4,379 ft. On June 30 during coring operations, circulation was lost at 4,383 ft. Circulation was regained, and coring operations continued to 4,404 ft, at which time lost returns occurred again. Following the lost circulation at 4,044 ft, the decision was made to abandon any further coring operations; the well was drilled to a total depth of 4,798 ft.

As of December 1991, the wellbore is temporarily abandoned. The wellbore sketch is shown in Figure 19.

4.1.1 Drilling Fluids and Borehole Stability

The VISPLEX drilling fluid system was selected for the Davis sandstone section of the Data Well No. 1. VISPLEX is a water-based, bentonite, aluminum-magnesium hydroxide system and has been shown to be effective in eliminating substandard borehole conditions (i.e., enlarged, rugose hole). These phenomenon have been observed and documented on numerous wells drilled through the Davis sandstone interval in the Fort Worth Basin of north central Texas. These conditions substantially contribute to the degradation of geophysical wireline log data and therefore require special design considerations to minimize their effects. In addition, plans were to run a string of 3-1/2-in. O.D. geophones attached to the outside of the 7-in. casing string after enlarging the hole from 8-3/4 in. to 12-1/4 in. To insure a quality cement job, it was imperative that a gauge borehole be drilled. Based on these criteria, the VISPLEX drilling fluid system was selected for drilling the Davis interval of Data Well No. 1. Table 5 summarizes the actual major drilling fluid properties for the main borehole and compares these values to the planned values.

During open-hole stress test operations at a depth of 4,145 ft, the open-hole packer became stuck while tripping in the hole at 3,900 ft, apparently due to suspended drill cuttings in the

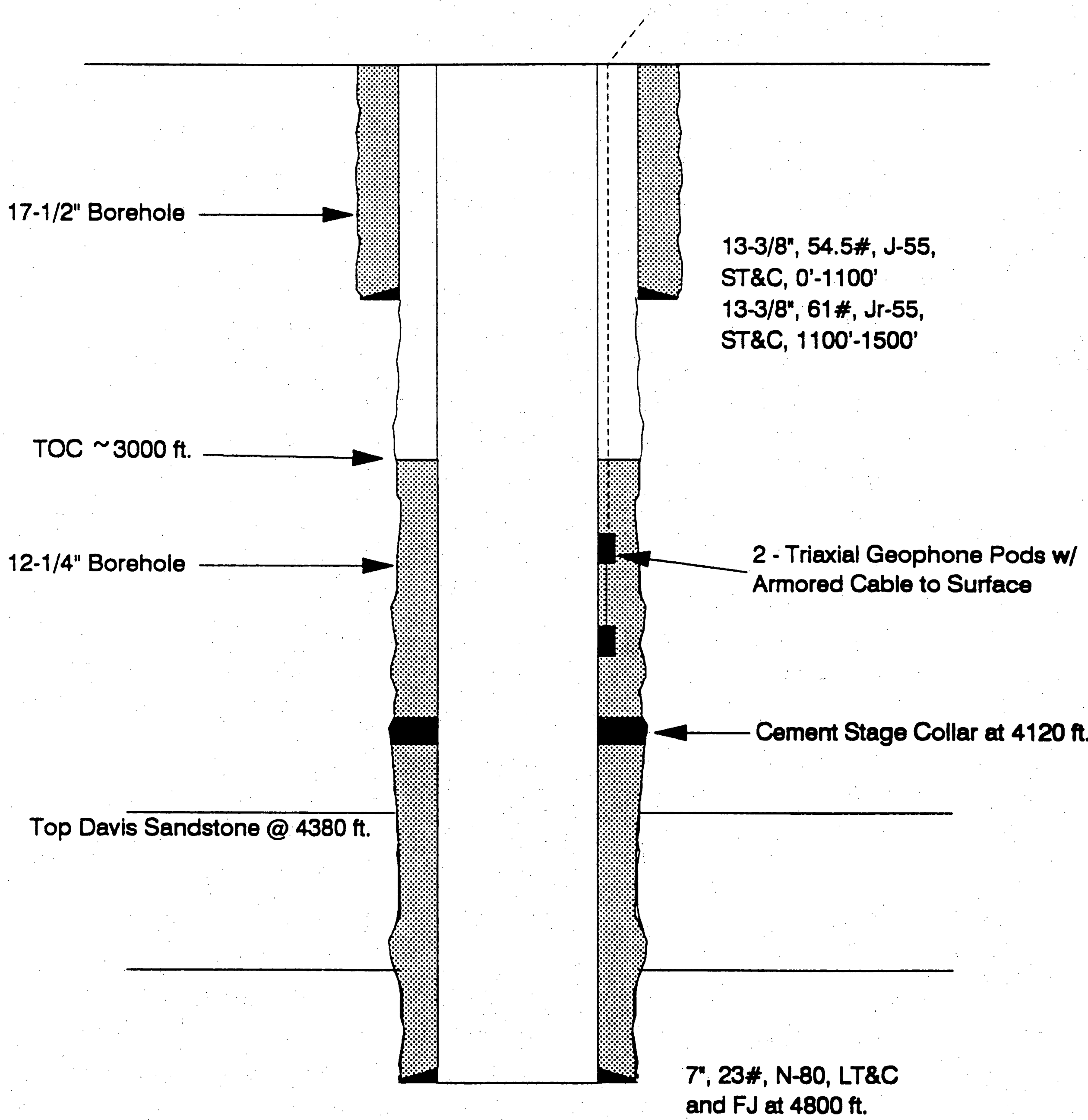


Figure 17 Data Well No. 1 Original Wellbore Design

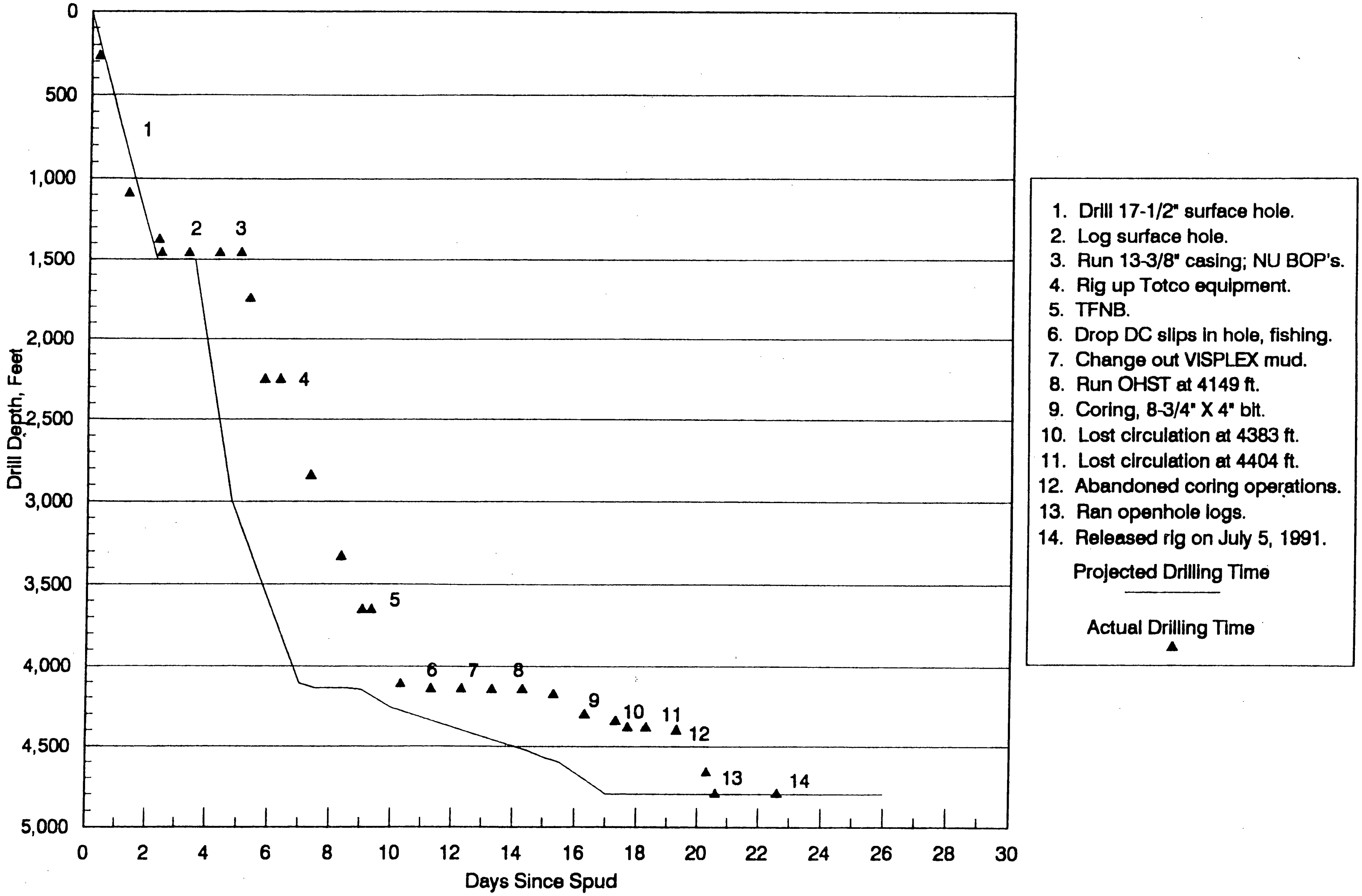


Figure 18 Drilling Curve for Data Well No. 1

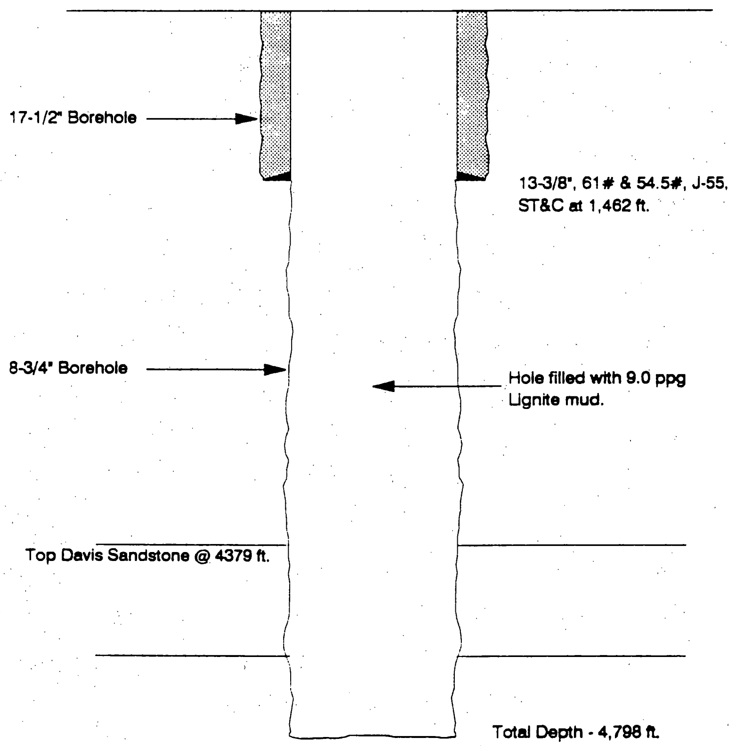


Figure 19 Data Well No. 1 Wellbore Status as of December 1991

Table 5 Selected VISPLEX Mud Properties for Depth Interval 1,462 to 4,145 ft, Data Well No. 1

Mud Property	Planned Values	Actual Values
Mud Weight, lb/gal	8.6 - 9.0	8.6 - 9.1
Viscosity, sec/qt	45 - 80	43 - 63
Filtrate, cc/30 min	4 - 6	43 - 63
Plastic Viscosity, cp	10 - 15	7 - 16
Yield Point, lbs/100 ft^2	20 - 40	13 - 26
Gel, 10 sec	20 - 40	43 - 105
6 RPM	20 - 40	12 - 20
3 RPM	20 - 40	11 - 20
Percent Solids	4 - 6	1.9 - 4.8
pH	9.5 - 10.5	11.2 - 12.0

borehole. It was not possible to pull the packer free, and it had to be jarred loose. All evidence implied that the 8-3/4-in. borehole was in gauge as a result of the inhibitive and rheological characteristics provided by the VISPLEX system. Due to the close tolerances between the 8-3/4-in. borehole and the outside diameter of the open-hole packer and the suspected presence of suspended cuttings, the decision was made to convert the mud over to a dispersed lignite system.

4.1.2 Casing and Cementing Operations

The Texas Department of Water Resources required surface casing at Data Well No. 1 to be set at a minimum depth of 1,000 ft to protect shallow fresh water sands. However, since Data Well No. 1 was to be used for future microseismic experiments, surface casing was actually set to 1,462 ft to protect the wellbore from a shallow, low-pressure gas sand located at 1,390 ft. Thirty-six joints of 13-3/8-in., 61 lb/ft and 54.5 lb/ft, J-55, ST&C casing were run and successfully cemented with 1,275 sacks of cement. Full returns were maintained while pumping, and 164 bbls of excess cement was circulated to surface.

After reaching the total depth of 4,798 ft, the decision was made to suspend further operations and to temporarily abandon Data Well No. 1. The current status and future plans for Data Well No. 1 are discussed in Section 5.0 of this report.

4.2 DATA ACQUISITION PROGRAM OBJECTIVES AND RESULTS

4.2.1 Coring and Core Orientation

Program Objectives

In designing the coring and core orientation program for the Data Well No. 1, the primary goal was to acquire rock samples across key intervals which would have an impact on determining the suitability of the Davis sandstone as a HFTS candidate formation.

The first priority was to acquire oriented core through the entire Davis sandstone section and adjacent lithologies. With this core, the geologic character of the Davis sandstone could be directly observed and its suitability for HFTS experimentation assessed. The rock acquired from the Davis sandstone and adjacent shales would also be used for routine and special core analyses that would support formation evaluation and fracture diagnostics objectives. Oriented core data acquired in this interval would be used for core analyses (e.g., acoustic anisotropy) and core fracture descriptions.

To support interpretations of hydraulic fracture azimuth, a key unknown on the proposed HFTS, over-coring and orientation of an induced open-hole stress test fracture was also planned. In this effort, the interval immediately above the stress test depth was also of interest for rock-type verification and rock mechanical properties core analysis testing. The interval where this test was planned was near the top of the Caddo Conglomerate, a shallower (within 200 ft of the top of the Davis), shaley sand interval.

Thus, with these objectives, 360 ft of core was planned in the following intervals of Data Well No. 1:

Interval, ft	Objective
4,115 - 4,175	Acquire core above the OHST, over-core the OHST induced fracture
4,270 - 4,540	Acquire continuous core in Davis Sandstone and bounding shale units
4,580 - 4,610	Acquire core in a postulated silty zone below the Davis Sandstone

Coring Program Results

Overall, the coring program resulted in the acquisition of 172 ft of 4-in. diameter core in the gross interval between 4,115 and 4,404 ft. Table 6 shows the results of individual core runs, and Figure 20 graphically illustrates the cored intervals.

A significant disparity exists between the planned 360-ft coring program and the 172-ft program actually implemented. This difference is directly related to operational problems experienced with the lost circulation at the top of the Davis Sandstone. It became obvious after coring several feet into the Davis that lost circulation could not be resolved with a core barrel in the hole. In addition, there was a risk associated with the core barrel sticking if returns were lost during coring operations. Therefore, after coring only the uppermost portion of the Davis Sandstone, a decision was made to abandon the remainder of the coring program and drill to total depth.

Table 6 Summary of Cored Intervals from D-1

Core No.	Interval Cut, ft	Interval Recovered, ft	Percent Recovery
1	4,115.0 - 4,145.0	4,115.0 - 4,138.3	78
2	4,149.0 - 4,179.0	4,149.0 - 4,178.5	98
3	4,270.0 - 4,330.9	4,270.0 - 4,330.9	100
4	4,330.9 - 4,336.4	4,330.9 - 4,331.5	11
5	4,335.0 - 4,386.0	4,334.8 - 4,384.6	97
6	4,396.0 - 4,404.0	4,396.0 - 4,403.5	93
Totals	185.4	171.6	92

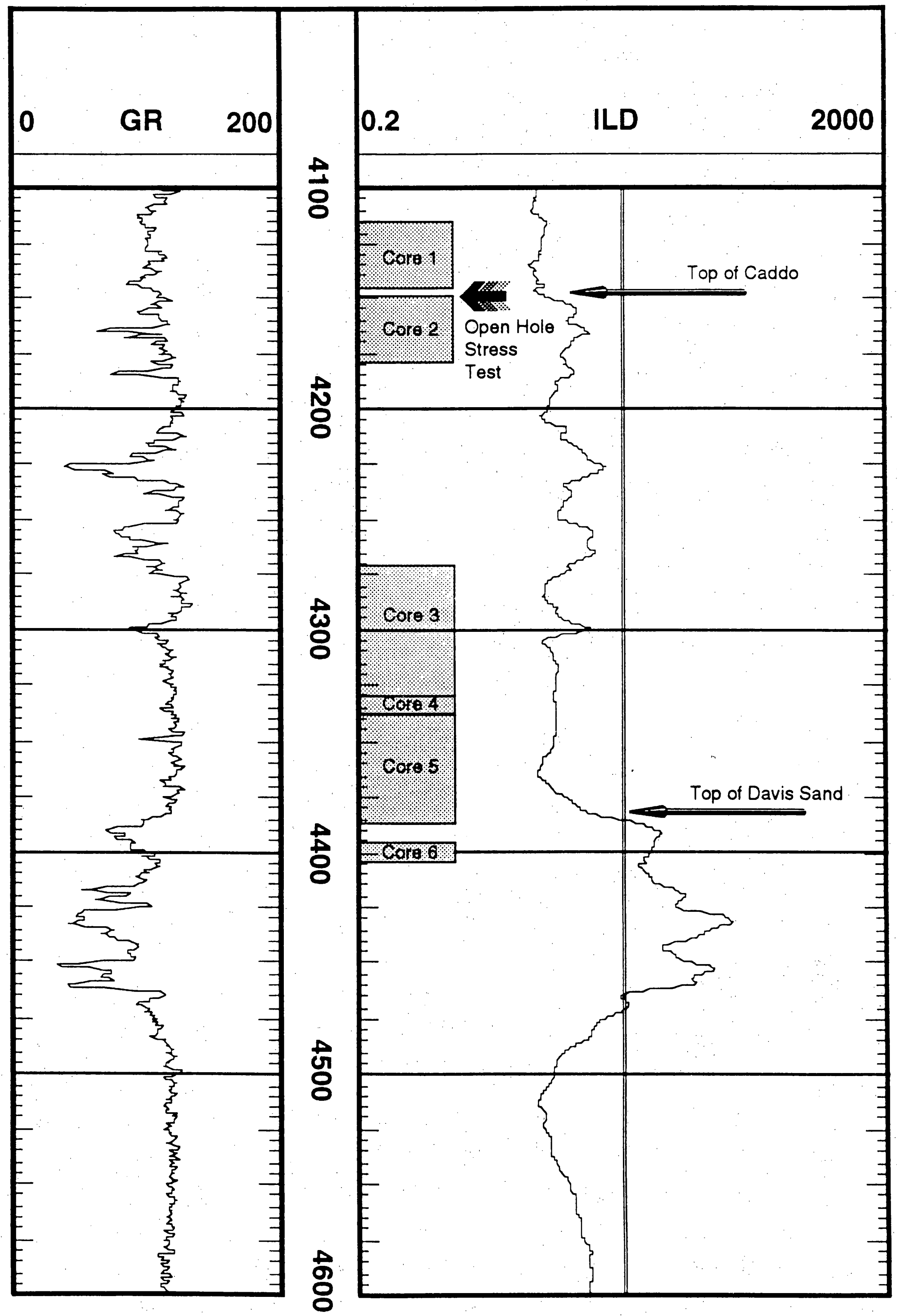


Figure 20 Cored Intervals in Data Well No. 1

4.2.2 Wireline Logging

Logging Objectives

A wireline logging program was designed for the Data Well No. 1 which would satisfy two project requirements: 1) determine whether the selected location is an appropriate site for fielding the hydraulic fracture experiments; and 2) if judged to be an appropriate site, acquire log data which would support the research emphasis on hydraulic fracturing to be conducted at the HFTS. Because of the research nature of the project, the logging service company and a logging research organization had also planned to field experimental tools. In its most basic form, however, the logging program was designed to provide data for determination of the following:

- reservoir characteristics including lithology, saturations, porosity, permeability and flushing characteristics;
- profile of rock mechanical properties and stress contrasts; and
- natural/induced fracture intensity and azimuth.

Two open-hole logging runs were planned for the well. Run No. 1 would be performed prior to running surface casing at a depth of 1,462 ft. Run No. 2 was planned after reaching total depth.

Logging Program Results

The data acquired through implementation of Logging Run No. 2 is summarized in Table 7. Similar to the coring program, there is a great disparity between the planned and actual programs. The severity of the lost circulation/fracturing had an immediate negative impact on the suitability of the site. Because of this negative impact, a decision was made to reduce the scale of the logging program. The data collected, however, provided the necessary data set to evaluate the stress characteristics of the Davis and adjacent strata, evaluate natural/induced fractures and perform basic formation evaluation.

Table 7 Log Data Acquired in Logging Run No. 2, Data Well No. 1

1. Phasor Induction/SFL/SP	4,777 - 3,790 ft
2. Digital Array Sonic	4,740 - 3,750 ft
3. Lithodensity/Caliper/GR	4,782 - 1,464 ft
4. Compensated Dual Neutron	4,760 - 3,736 ft
5. Natural Gamma Ray Spectrometry	4,718 - 3,758 ft
6. Microlog/Caliper	4,752 - 3,750 ft
7. Nuclear Porosity Lithology	4,750 - 3,750 ft
8. Formation Microscanner	4,511 - 4,013 ft

4.2.3 Surface Datalogging

Datalogging Objectives

In support of GRI research being conducted by Ercill Hunt & Associates (EHA) in the area of determination of rock stress from drilling parameters, comprehensive datalogging was planned as a part of the Data Well No. 1 program. Datalogging involves the monitoring and digital recording of depth, gas units, rotary speed, weight on bit, torque, pump pressure, pump speed and penetration rate. To further augment the data set, drillstring vibrational measurements were acquired from strain gauges and accelerometers located on the kelley. In addition, drilloff tests were planned in a number of Davis Sandstone intervals. During these tests, a predetermined rotary speed and bit weight are set and allowed to drill off (with the draw works brake locked) until the weight on the bit decreases to a lower pre-determined weight.

While collection of this data was not an integral part of the HFTS program, the D-1 well presented EHA the opportunity to collect high-quality drilling parameter data from which rock stress could be interpreted. These interpreted values could then be compared to cased-hole in-situ stress tests planned during the completion phase of Data Well No. 1.

Datalogging Results

Datalogging as described above was performed over the interval from 2,975 to 4,798 ft. A reduced-scale presentation of this data is included in the Appendix. In addition, seven drilloff tests were performed in the following intervals: 4,000 to 4,008 ft; 4,099 to 4,105 ft; 4,187 to 4,194 ft; 4,252 to 4,258 ft; 4,524 to 4,533 ft; 4,594 to 4,604 ft and 4,719 to 4,726 ft.

4.2.4 Open-Hole Stress Testing

Open-Hole Stress Testing Objectives

The objective of this testing was to determine, in the open-hole environment, the average in-situ closure stress in the marine shale interval of the Caddo facies above the Davis sandstone interval. In addition, the fracture induced by the open-hole stress test was to be overcored and its characteristics observed directly. Through orientation of the fracture included in the core and by images of the formation microscanner log, fracture azimuth could be derived.

Open-Hole Stress Testing Results

One open-hole stress test was conducted during drilling operations in the marine shale of the Caddo facies above the Davis sandstone interval. The open-hole stress test was performed on June 27, 1991, after reaching a depth of 4,149 ft. DST type packers were set at 4,135 ft with a perforated anchor pipe touching bottom at 4,149 ft; thus, the marine shale tested was in the interval from 4,135 to 4,149 ft. Bottomhole pressures were measured using a downhole pressure gauge with surface readout. In addition, bottomhole temperature, injection rate, surface injection pressure and surface annulus pressure were monitored and recorded with the GRI Treatment Analysis Unit.

Injection tests were conducted using 2 percent KCl water at an injection rate of 10 gal/min. Initial attempts to breakdown the marine shale were unsuccessful and the maximum surface pressure of 2,000 psi was reached. At this point, annulus pressure was increased to 250 psia. Further attempts to raise annulus pressure were not possible after an uphole annular zone broke down, and the annulus began taking fluid. Subsequent attempts to break down the marine shale were unsuccessful and finally, communication occurred between the drill pipe and the annulus. At this point, the open-hole stress test was terminated and the bottomhole assembly was retrieved from the hole. No data usable for interpretation of in-situ stress were acquired.

4.3 RESULTS OF ANALYSES

4.3.1 Well Log Analyses

Conventional Formation Evaluation

A computer log analysis model was developed for the Davis sandstone which used most of the basic log data available including density, delta rho, thermal neutron porosity, compressional travel time, shear travel time, gamma ray, percent potassium, photoelectric absorption cross section, deep resistivity and caliper data. The analysis shows that the Davis is best developed over the intervals 4,389.5 to 4,397.5 ft; 4,411.5 to 4,440.5 ft; and 4,447.5 to 4,461.0 ft.

The log analysis uses both a porosity cutoff and a clay volume cutoff. If the calculated porosity is less than 3 percent or if the clay volume in matrix is greater than 32 percent, the other reservoir parameters are not computed. A computed interval has a "net" thickness which passes these two cutoffs. Cutoffs delimit vertical reservoir compartments and provide more meaningful averages of reservoir parameters. In general, when the Davis is separated by non-reservoir barriers, the unit is broken into sub-units and accumulations and reservoir parameter averages are performed for each sub-unit.

Figure 21 is a computed log showing the calculated reservoir properties for Data Well No. 1. The reservoir properties log presents a bulk volume analysis of matrix and fluid components in Track 1. From left to right, the bulk volume includes clay, sand, carbonate, gas-filled porosity and water-filled porosity. Water saturation calculations are presented in Track 2. The dashed curve is the water saturation of the formation, i.e., a conventional shaly sand analysis using the deep resistivity log. The solid curve is the water saturation of the near-wellbore zone and is modeled from the response of either density and neutron logs or sonic and neutron logs. The dual calculation of deep and shallow water saturations provides a qualitative permeability indicator, i.e., the departure of the deep and shallow water saturation curves are an indication of flushing. Experience has shown that a sandstone generally must have greater than 0.01 millidarcy matrix permeability to show significant flushing (not to be confused with invasion into natural fractures which shows little expression on density and neutron logs). The difference between the deep saturation and the shallow saturation is called the flushing index. This index is accumulated throughout each zone in Track 2. Track 3 presents log-derived porosity. The porosity computation represents the average porosity in both sand and shale laminations. Track 3 also usually presents log-derived permeability; however, in the absence of core analysis data for the Davis, these computations would be speculative and are therefore not presented. Track 4 presents basic density porosity on a limestone matrix and corrected neutron porosity.

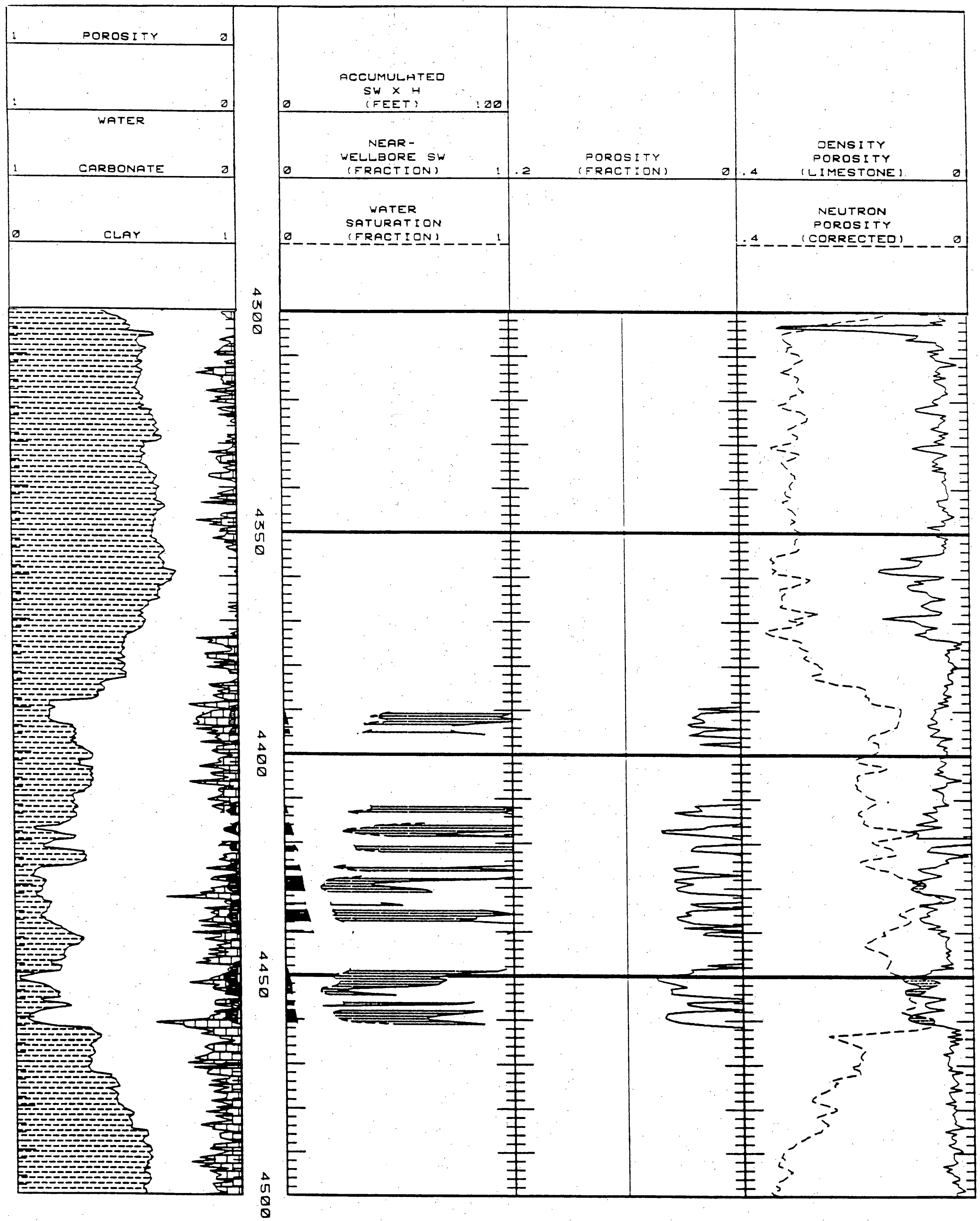


Figure 21 Computed Log Showing the Calculated Reservoir Properties for Data Well No. 1

Tabular log analysis results are presented in Table 8. Tabular results consist of top and bottom depths of each zone, gross thickness (Gross H) in ft, net thickness (Net H) in ft, average porosity (Avg ϕ in percent, maximum porosity (Max ϕ) in percent, average water saturation (Avg SW) in percent, minimum water saturation (Min SW) in percent, a summation of hydrocarbon-feet (HCFT) = [H x ϕ x (1 - Sw)] in ft, average clay volume in matrix (Avg Clay) in percent, and minimum clay volume in matrix (Min Clay) in percent.

Table 8 Summary of Reservoir Characteristics, HFTS Data Well No. 1

Interval, ft	Gross H, ft	Net H, ft	Avg ϕ, %	Max ϕ, %	Avg SW, %	Min SW, %	HCFT, ft	Avg Clay, %	Min Clay, %
4,389.5 - 4,397.5	8.5	6.0	3.7	4.6	40.4	32.3	0.135	21.0	16.2
4,411.5 - 4,440.5	29.5	19.0	4.5	7.0	27.3	15.8	0.635	17.5	7.9
4,447.5 - 4,461.0	14.0	12.0	5.4	7.4	24.7	15.5	0.498	12.8	2.1

Based on the log analysis of the Davis Sandstone in Data Well No. 1, it is interpreted to be a thinly-laminated sand/shale sequence. This interpretation is confirmed by the detailed lithologic descriptions of Data Well No. 1 core samples (Texas Bureau of Economic Geology, unpublished report, 1991). The Davis sandstone is calcareous and shows a higher carbonate content in the sandier intervals. There are three principal intervals having a higher percentage of sand laminations; these are separated by intervals having more shale. The analysis shows that the Davis is best developed over the intervals 4,389.5 to 4,397.5 ft; 4,411.5 to 4,440.5 ft; and 4,447.5 to 4,461.0 ft.

Based on the evaluation of the log data, the mineralogy of the Davis sandstone is relatively simple. The sandstone laminations are dominantly quartzose in composition, and potassium feldspars do not appear to be significant. Clay content is as low as 2 percent; however, it is more typically 13 to 21 percent in the net reservoir. The dominant clays are interpreted to be illite or mixed-layer illite/smectite; however, it is interpreted that chlorite and/or kaolinite are significant. The ratio of the different clay minerals in adjacent sands and shales within and above the Davis is interpreted as being constant; however, the ratio of chlorite and/or kaolinite of the Pregnant Shale below the Davis is increased.

The gross thickness of the Davis sandstone is 72 ft and the net thickness is 37 ft. Maximum porosity is 7.4 percent, and the net reservoir averages 3.7 to 5.4 percent. It should be emphasized, however, that this porosity is an average porosity within both sand and shale laminations and that the porosity of individual sand laminae would surely be higher. The lowest water saturation in the Davis is 15.5 percent, and the net reservoir averages between 24.7 and 40.4 percent. Formation water resistivity is 0.03 Ω-M. The water saturation is apparently at irreducible, and the higher water saturations indicate shalier and tighter reservoir rather than a potential water production problem. The relatively low water saturations of several of the sandier intervals indicate an absolute permeability that is higher than 0.1 md. The flushing characteristics as interpreted from the dual saturation analysis indicates an absolute permeability that is much greater than 0.01 md.

Stress Profiling

The stress profile/mechanical properties log is presented in Figure 22. The travel time data that was generated by the Schlumberger Computing Center is presented in Track 4. Gas-corrected compressional travel time and gas-corrected shear travel time are input to compute Poisson's Ratio which is presented as a solid curve in Track 3. Young's Modulus is also computed when density data is valid and is presented as the dashed curve in Track 3. Closure stress is presented in Track 2 as a solid curve. Closure stress is based upon an empirical relationship involving Poisson's Ratio, overburden pressure, pore pressure and residual tectonic stress. The pore pressure gradient used for these computations is 0.32 psi/ft. The stress profile indicates that the vertical stress contrast between the Davis Sandstone and the confining shale averages about 500 psi and is as large as 800 psi. There are no stress measurements to calibrate the log-derived closure stress. Poisson's Ratio averages about 0.34 for shale and about 0.24 for the Davis Sandstone. Young's Modulus averages about 2.5 x 10^6 psi for shale and about 5.0 x 10^6 psi for the Davis. For all practical purposes, the Davis would probably behave as a single unit when hydraulically fractured because the stress contrasts between the sandier sub-units and the shalier intervals are not large. Also, the shalier sub-intervals within the Davis are not thick.

4.3.2 Natural and Induced Fracture Analyses

Through direct observation of core in the upper part of the Davis Sandstone and remotely through borehole image log (Formation MicroScanner) data through the entire Davis section, fractures in the Davis Sandstone were described by GRI contractors Texas Bureau of Economic Geology, CER Corporation and Sandia National Laboratory. The following sections represent a composite view of their interpretations.

Core Fracture Descriptions

The top of the Davis sandstone was encountered at 4,371 ft which is the top of the 19 ft transition from shale to sandstone. Lost circulation was initially encountered at a depth of 4,386 ft (core depth) while cutting Core No. 5. This problem terminated Core Run No. 5; however, no fractures were observed in the bottom of the cored interval. The lost circulation problem was remedied by drilling an additional 10 ft while circulating and conditioning the mud. In cutting Core No. 6, only 8 ft was cored before losing returns again and terminating the core run. However, the 7.5 ft recovered in the interval from 4,396.0 to 4,403.5 ft contained an array of interconnected natural and drilling-induced fractures.

The subvertical natural extension fractures recovered in Core No. 6, as shown in Figures 23 and 24 (a through d), form an interconnected network composed of three major subparallel strands (between 4,397 and 4,402 ft) and numerous shorter isolated splays. The three major strands are 2 ft, 2.5 ft and 3 ft long, respectively. The strands divide and join, and numerous subsidiary fractures are present where major strands overlap, creating zones of closely spaced fractures (see Figure 23) over distances as much as 0.5 ft.

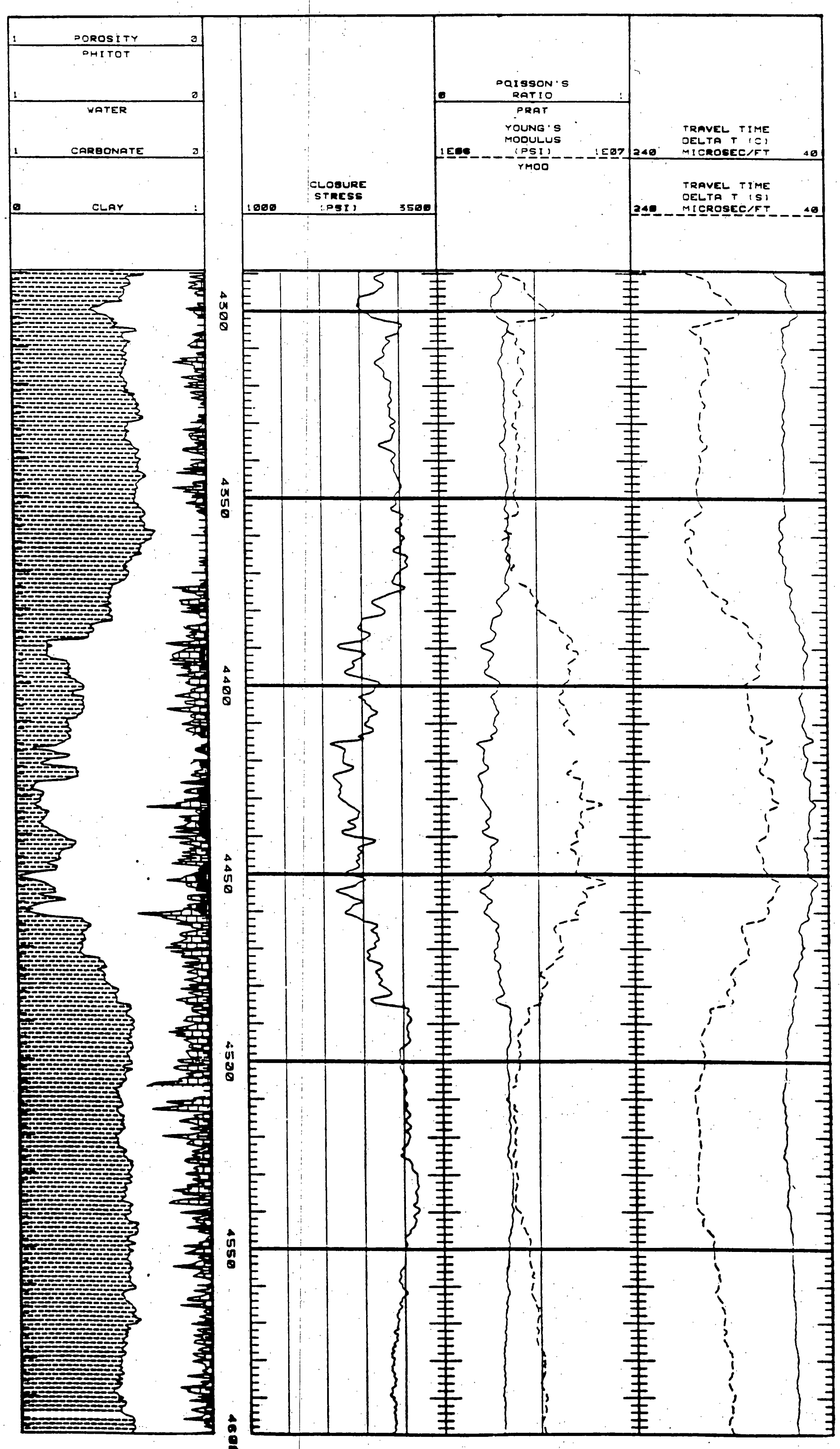


Figure 22 Stress Profile and Mechanical Properties Log for the Data Well No. 1

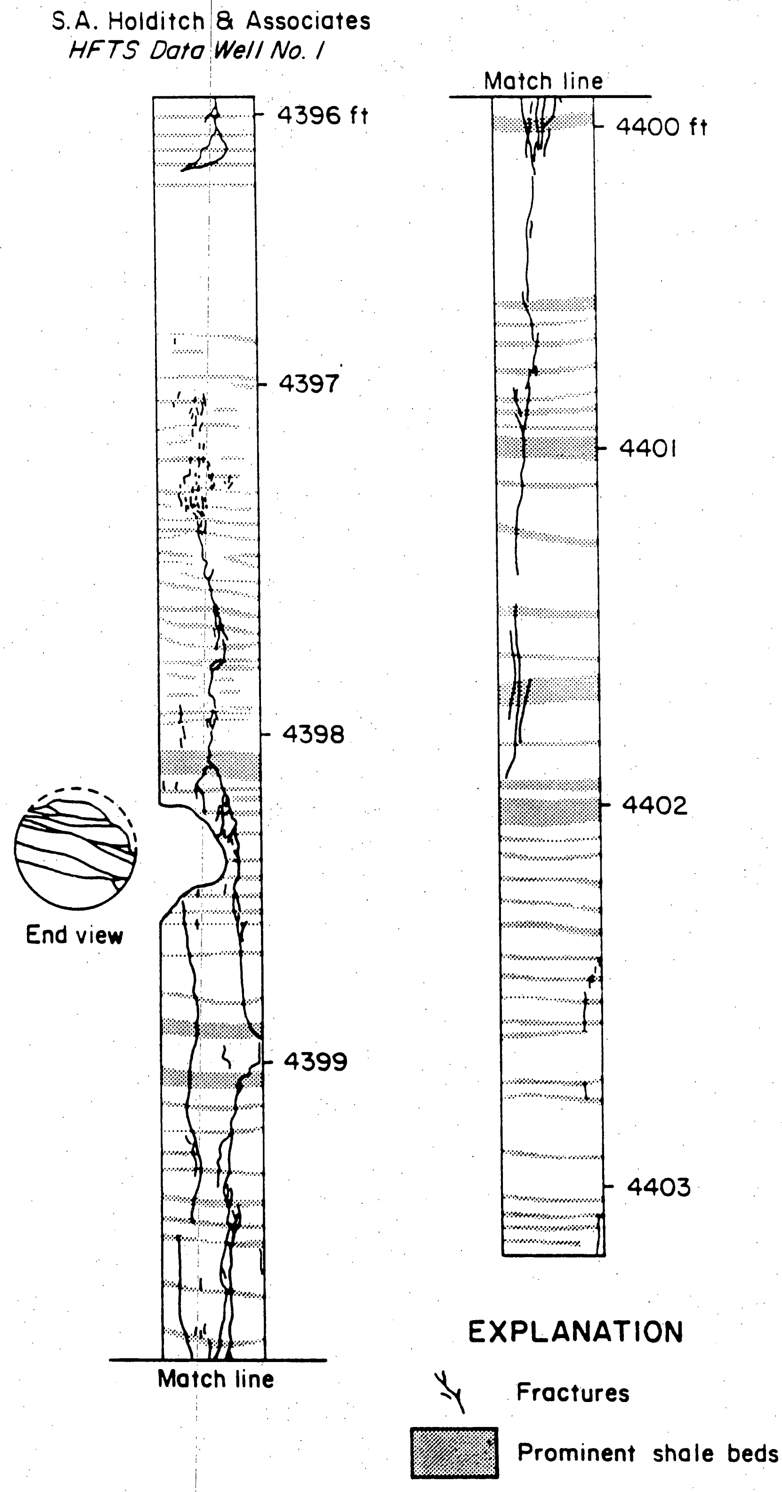


Figure 23 Sketch of Fracture Davis Sandstone Core Recovered in Core No. 6, Data Well No. 1

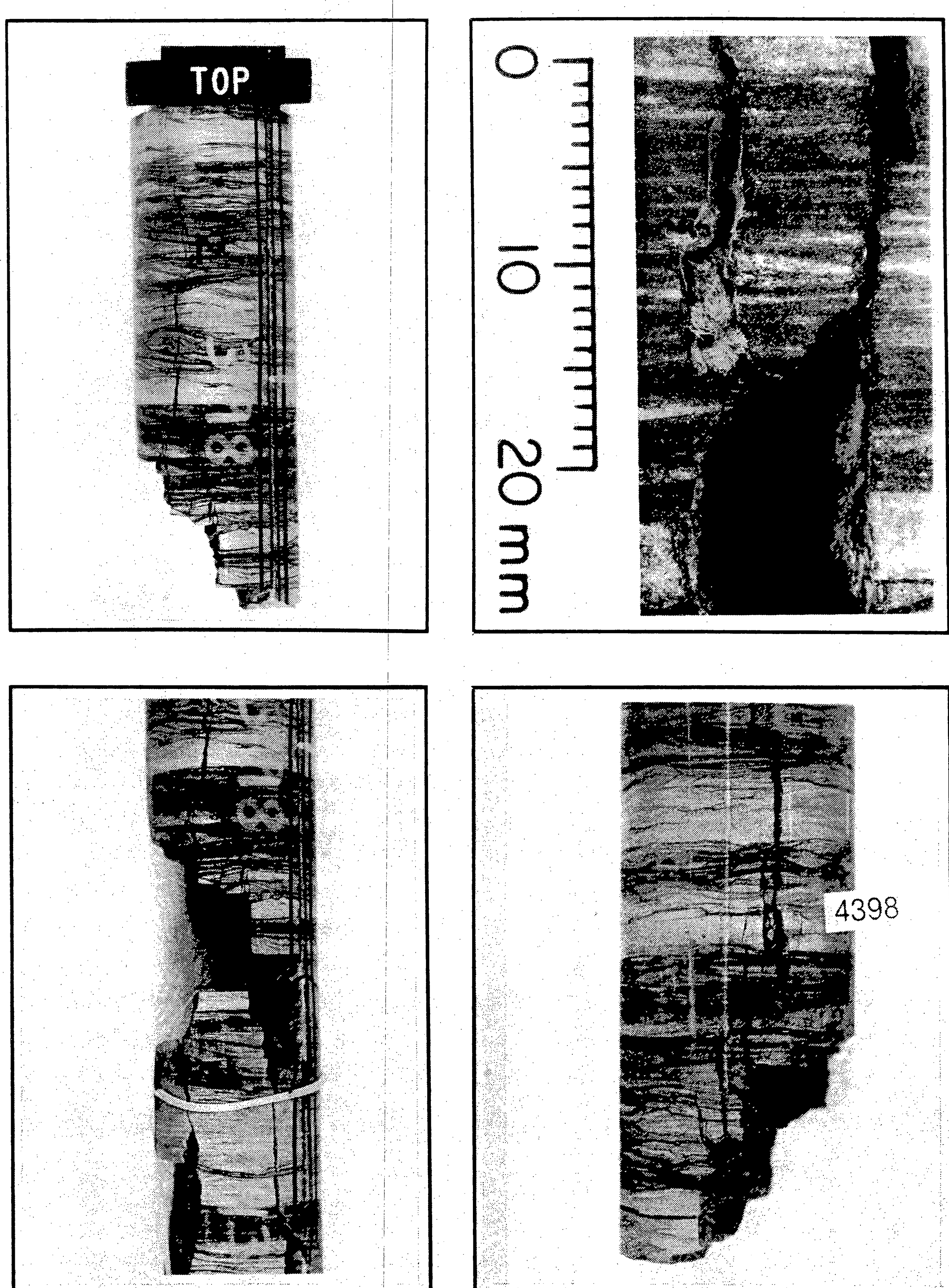


Figure 24 Photos Illustrating the Character of Fracturing Observed in Core No. 6

Fractures in the sandstone have fairly smooth surfaces, but fracture surfaces are very rough in intervals with thin (e.g., 0.5 to 2 cm), interbedded sandstone and shale beds. This is because fractures and fracture segments in shale have shallower inclinations than those in sandstone. Some fractures crossing shale layers are nearly parallel to bedding.

In the sandstone, fracture-filling calcite is commonly visible as a 0.5 to 1 mm veneer on fracture surfaces and as disseminated crystals. Locally, calcite fill contains smooth fractures that presumably formed during coring operations. Large (1-2 mm diameter), isolated subhedral calcite crystals apparently mark areas where primary fracture porosity was present. The heights of these crystals can be used to infer in-situ fracture widths of approximately 1 mm. Particles of lost circulation material are wedged into several of the fractures as shown in Figure 24b.

Borehole Image Log Fracture Descriptions

In the final logging run on Data Well No. 1, data from Schlumberger's FMS was used to augment the fracture characterizations from core. The FMS data showed fractures in the following intervals: 4,372 ft to 4,406 ft; 4,415 ft to 4,452 ft; and 4,506 ft to 4,511 ft (log depths). These intervals, however, appear not to be fractured in the sense of having numerous fractures throughout. Rather, there are just four very long fractures which may have minor splays from the main fracture trace. Two fractures which overlap and appear to be multi-segmented are present in the 4,372 to 4,406 ft fracture interval. The fracture between 4,415 and 4,452 ft is unusual in that it stays within the borehole for its entire 37-ft length. This fracture is interpreted to be an induced extension of existing natural fractures encountered in the top of the Davis. In this interpretation, the natural fractures provide zones of weakness in the underpressured Davis Sandstone. These zones of weakness are easily inflated and extended by the hydrostatic pressure of 9.1 ppg drilling fluid.

The two fractures in the 4,372 to 4,406 ft interval have strikes of N12°E and N5°E. The fracture in the interval from 4,415 to 4,452 ft strikes N12°W, and the fracture in the interval from 4,506 to 4,511 ft strikes N38°E. As was shown in Figure 15, the nearly north-south strikes are consistent with FMS fractures interpreted in the Dallas Production Sallie Hill "A" No. 1 well, nine miles to the west of Data Well No. 1 (CER Corporation, 1992).

Influence of Fractures on Drilling

While drilling through the top of the Davis sandstone, lost circulation has been previously observed by several operators in the Fort Worth Basin, and some operators ascribed this to the presence of conductive natural fractures. During coring and drilling of the Davis in the HFTS Data Well No. 1, a minimum of 1,000 bbls of drilling mud and lost circulation material were lost. From part of the upper Davis where circulation was initially lost, 7.5 ft (2.3 m) of sandstone and interbedded shale core was recovered. Natural fractures are abundant in this core, and lost circulation material is imbedded in several of the fracture strands, clear evidence that fractures were naturally open or were dilated during coring. Core observations from the HFTS Data Well No. 1 provide evidence of high fracture connectivity among fractures with heights in core of several feet (Figure 23). However, it could not precisely be determined how many of the connected fractures in this core are natural. The higher connectivity corresponds to areas of enhanced permeability, as indicated by rapid and extensive lost circulation during drilling. There is no direct evidence for lateral (plan view) extent of this fracture network, but the volume of mud and circulation material lost in this interval suggests that the fractured zone could be extensive.

Lost circulation has been reported from several areas of Davis production in the Fort Worth Basin, but any pattern that may exist has not yet been documented. Because drilling procedures and other factors can influence lost circulation, assessing the role of natural fractures in the Davis sandstone from this type of data requires further research.

Stress Directions

The orientation in which natural fractures are likely to be open can be strongly influenced by in-situ stress directions. On a regional scale, maximum horizontal compressive stress in the Fort Worth Basin is inferred to trend northeast (Zoback and Zoback, 1989). Local data from HFTS Data Well No. 1 and the Sallie Hill "A" No. 1 support this interpretation. A stress test conducted in shale about 120 ft (36.5 m) above the top of the Davis Sandstone in the HFTS Data Well No. 1 created a fracture which was subsequently overcored and oriented. The strike of this OHST fracture was found to be N36°E. The results from HFTS Data Well No. 1 broadly agree with maximum horizontal stresses inferred from borehole breakouts, which range from N38°E to N40°E, and the north to north-northeast strike of fractures induced by drilling and coring. Because the north-northeast striking natural fractures are approximately parallel to the maximum horizontal compressive stress, they are more likely to be open in the subsurface than are fractures in other orientations. Thus, they are able to contribute to the permeability of the formation or to interfere with drilling and hydraulic fracture treatment operations by accepting fluid.

Predicting Fracture Occurrence

The abundance of fractures in the core studied and the occurrence of rapid lost circulation in fractured intervals suggest that fractures are an important reservoir element in Davis sandstone. Evidence for the origin of Davis sandstone fractures may help guide predictions of where fractures may be more common or better interconnected in this unit. As shown in Figure 25, the Sallie Hill "A" No. 1 and HFTS Data Well No. 1 are not near any mappable folds or faults and only a subtle northwest-trending fold or small fault can be inferred near the Hastings No. 4 well; therefore, local deformation near mappable structures cannot account for the observed fractures. Although folds and faults are likely to be associated with more abundant subsidiary fractures, the fractures which were observed may instead be primarily regional ones that result from basin-scale lateral tectonic strains. In the Davis sandstone, the close association of many small fractures with stylolites suggests that vertical flattening also played a role in fracture genesis.

Regional fractures commonly occur in sets that have similar orientations over wide areas. For thin beds, fracture spacing in such sets is commonly approximately equivalent to or slightly less than the bed thickness. However, this relationship is not seen in thin-bedded Davis sandstone core, so fracture abundance cannot be predicted from bed thickness in this case. Clustering of fractures into swarms is an attribute of regional fractures that can account for areas of great fracture density within regional fracture sets (Laubach, 1991), but predicting the occurrence of swarms in flat-lying rocks is challenging. Future research on Davis sandstone fractures may clarify if rock properties or diagenetic history (which can strongly influence rock properties) can be used to help predict regional fracture occurrence patterns in this sandstone, as can be done in some other formations (Laubach, 1989).

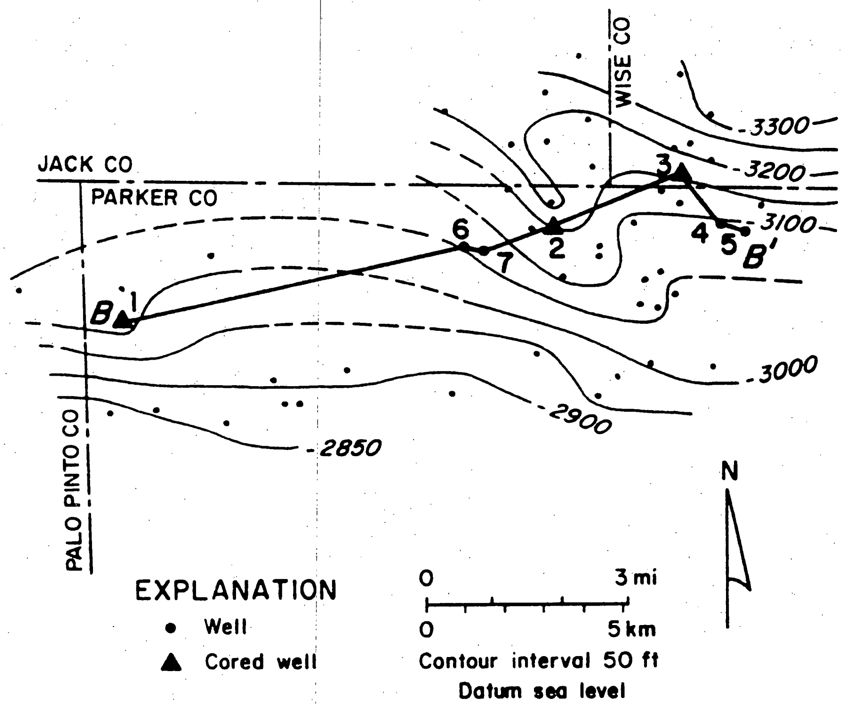


Figure 25 Structure Contour Map on the Top of the Davis in the HFTS Study Area

5.0 Current Status

Data Well No. 1 was temporarily abandoned on July 5, 1991. S. A. Holditch & Associates, Inc., operator of the well, received permission from the Railroad Commission of Texas to temporarily abandon the well for a period of 90 days to allow the GRI contractors to analyze data collected during the open-hole program. Due to extensive lost circulation problems in the Davis sandstone interval as well as numerous natural and induced fractures observed in the core and FMS log, the decision was made to not set casing on this well and suspend further operations in the Davis.

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Appendix

DATALOG