IMPROVING RETURN ON HYDRAULIC FRACTURE TREATMENT INVESTMENT WITH WIRELINE INPUTS

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ABSTRACT

The Permian basin of west Texas is known for its low permeability reservoirs, earning it the reputation of "hard rock country." A significant percentage of the wells completed here require hydraulic fracture treatments in order to produce economic quantities of oil and gas. The hydraulic fracture treatment can represent a significant portion of the total well cost. In addition, the effectiveness of the treatment can be critical to the economics of the well. Too small a treatment can leave valuable hydrocarbons in the ground. Too large a treatment can be equally inefficient and possibly ruin the well.

Knowledge of the rock elastic properties and in-situ stress distribution is critical to determining the induced fracture geometry. With full sonic waveform data now available, the dynamic elastic properties of the rock can be directly measured. Poisson's ratio (v) can be directly obtained from the shear and compressional transit times. From the v/(1-v) relationship the horizontal stress component of vertical overburden stress can be obtained. When this is combined with pore pressure and bulk density data a relative closure stress value can be obtained. The final product is called the FracHite* log. As of this writing, over 450 wells have been evaluated with this technique. Several single-zone and multiple-zone field cases are presented here to illustrate the applications of the technique in the Permian basin. In addition, a 2D hydraulic fracture model is used in conjunction with actual decline curve data to illustrate the specific benefits of accurate hydraulic fracture height data. The case study utilizes data from a representative producing San Andres well in Ector County.

An additional item of importance is the orientation of the hydraulic fracture. This is critical to designing an efficient drainage pattern in a field. It is now generally accepted that the hydraulic fracture follows a two-wing pattern dictated by the natural stress distribution in the rock. With the eight button Dual Dipmeter* and the FILMAP presentation this natural stress distribution can be mapped with an unprecendented degree of accuracy. Nine Spraberry/Dean wells were evaluated using the Dual Dipmeter, and the results are presented on a map of Midland and Martin Counties.

*Mark of Schlumberger

PART I - PERMIAN BASIN FracHite APPLICATIONS

The theory behind the FracHite log is discussed thoroughly by Newberry, Nelson, and Ahmed in references (1) and (2). A brief summary is provided here. The heart of the FracHite model is the borehole sonic tool shear and compressional wave slowness, measured with either the Long Spacing Sonic tool or the Digital Sonic tool. The shear wave slowness is a measure of the reaction of the rock to a stress in the transverse direction. The compressional wave slowness is a measure of the reaction of the rock to a longitudinal stress. By combining the two measurements with bulk density it is possible to directly calculate Poisson's ratio and Young's modulus. The dynamic definition of Poisson's ratio is:

$$v = [\,0.5\,(Vc/Vs)^2 - 1] \,/\, [\,(Vc/Vs)^2 - 1] \qquad (1)$$

and the dynamic definition of Young's modulus is:

$$E = pb\, Vs^2\, [\,(\,3Vc^2 - 4Vs^2\,) \,/\, (Vc^2 \,/\, Vs^2\,) * 2.15 * 10^8\,] \qquad (2)$$

where Vc = compressional slowness
Vs = shear slowness
pb = bulk density of the rock

Once a hydraulic fracture has been initiated, the pressure necessary to hold the fracture open is equal to the minimum total horizontal stress. This stress is often referred to as closure stress or fracture gradient pressure. In tectonically relaxed areas, this stress is usually horizontal, and the principal vertical stress is the overburden stress. This overburden stress can be calculated from bulk density measurements over the logged interval and assumed to be a block value above the logged interval. It is also a function of the pore pressure gradient. This vertical stress gradient is normally in the range of 1 psi/ft. It can be directly related to the minimum horizontal stress by the (v/1-v) function (see reference 1). This minimum horizontal stress is presented on the FracHite log as the Closure Stress Gradient (see figure 1.)

Single-Zone Implementation

The main concern in designing a single zone fracture treatment is maximizing length while minimizing height. The Closure Stress Gradient is the starting point for analyzing the data. The extent of fracture height migration is dependent on the relative closure stress between points. Absolute closure stress values from the log are not a factor in this respect. Each well may have an offset to this log-measured closure stress value due to variations in tectonics, overburden assumptions above the logged interval, and variations in pore pressure from well to well. In the Permian basin, the major offsetting factor appears to be the pore pressure, with the tectonic and overburden offsets having an insignificant effect in most areas. The pore pressure value can be directly measured with the Repeat Formation Tester tool or a drillstem test. Both methods also obtain a permeability value when measuring the pore pressure. Permeability is a critical input to both the frac fluid efficiency calculations and to the created hydraulic fracture permeability calculations.

With regard to applying the FracHite log; the absence of pore pressure, overburden, and tectonic stress data does not significantly affect the use of the measured closure stress gradient. The effect on fracture height migration is usually insignificant since relative values are used. The actual gradient, however, can be normalized by a pump in/flow back test described by Nolte and Smith (reference 3).

This should be done in any event to obtain the reference point for the widely used Nolte-Smith plot. The pump-in/flow back test involves pumping a small volume of pre-pad and observing the closure pressure as the fluid flows back into the wellbore. This closure pressure is equivalent to the zero point on the delta pressure curve and the Nolte-Smith plot (see the "delta pressure" output on figure 1). If this test fails to produce a clear value, the bottom hole fracture pressure immediately after the tensile strength of the rock has been overcome should be used as the closure pressure value. The maximum bottom hole fracture pressure for the job should be this closure pressure plus the delta pressure required to stay in zone, less the perforation friction pressure.

During the course of the job, this bottomhole fracture pressure should be monitored and continuously plotted on a log-log scale. The monitoring can be done with either a downhole tool or by monitoring the surface pressure of a dead string of fluid. This dead string can be either inside or outside tubing. Where this is not practical (i.e. where friction pressure would be excessive or where the tubing is sealed off with a packer) then a margin for error should be allowed. There is quite often a variance between bottomhole frac pressures measured by the dead string and bottomhole frac pressures predicted from the surface pressures, regardless of the degree of sophistication of the surface monitoring equipment. This is especially true at high rates and viscosities or with smaller casing or tubing. If there is a critical delta pressure for the job (i.e. if an aquifer is close) then this margin of error may be unacceptable. In most cases the economic performance will improve with length, and length will improve if the pressure is increased as close to the containment limit as possible. This should be justification for a dead string when friction pressures permit. If the surface treating pressures with tubing in the hole are excessive or uneconomical, then a computer van analysis of bottomhole frac pressure should be considered as a second alternative. Only as a last resort should the bottomhole pressure be hand calculated from surface pressures if a critical delta pressure is involved.

If the bottomhole fracture pressure during the job reaches the containment limit, two options then exist. The first is to lower the pump rate at the surface, assuming the new rate can still carry the proppant. Depending on the type of fluid, lowering the rate may or may not decrease the pressure. Many fluids are shear sensitive and lowering the rate may increase the viscosity. If lowering the rate is ineffective, the second option is to flush the sand from the borehole and terminate the job.

To demonstrate the local applications of the FracHite log, four single-zone and four multiple-zone examples follow. Over 150 FracHite logs have been run in the Permian basin in every formation that is hydraulically fractured. The examples presented will illustrate that the FracHite log can accurately predict the height of a hydraulic fracture in the Permian basin, as well as predict which zones will receive major or minor treatment.

Single-Zone Applications

EXAMPLE 1 - SPRABERRY FORMATION, BORDEN COUNTY

In order to keep the frac in zone and maximize length, a 150 psi delta pressure limitation was recommended by the FracHite log. The treatment was allowed to reach 300 psi near the end of the job, even though the rate was reduced from offset treatments to help stay in zone. The after-frac survey indicates the treatment went out of zone as predicted, with a created height of 77 feet above the zone. The height below the zone was not available due to fill.

EXAMPLE 2 - SPRABERRY FORMATION, BORDEN COUNTY

This well is an offset to Example 1, with perforations in the same zone. The recommended delta pressure limitation from the FracHite log was 200 psi. The treatment stayed within this limitation, and the frac stayed in zone as predicted. The after-frac survey supports this and indicates a created height above the zone of 10 feet.

EXAMPLE 3 - CANYON FORMATION, TOM GREEN COUNTY

The operator had two objectives in mind in using the FracHite log. First of all, he wanted to keep the frac in zone. Secondly, he wanted to have an accurate height so that the possibility of prematurely screening out could be minimized. This was a common problem in the area. A delta pressure limitation of 900 psi was recommended from the FracHite log, along with a height of 72 feet. The job was successfully put away using this limitation, and the after-frac survey indicates that the actual height was 74 feet.

EXAMPLE 4 - DELAWARE MOUNTAIN GROUP, REEVES COUNTY

Operator desired to stay in zone and maximize frac length. The FracHite log indicated that 200 psi was the delta pressure limit for the job to stay in zone. The job was put away with a 161 psi delta pressure. The predicted height for this pressure was 28 feet. The after-frac survey indicated a height of 29 feet.

Multiple-Zone Applications

The addition of pay zones to the treatment adds some complexity to the design, however the same Closure Stress Gradient data are used. In the multiple-zone case the difference in stress between the pay zones and the boundaries is still a factor. In addition, the difference in closure stress between the various pay zones becomes important as well. The difference in frac fluid hydraostatic head enters into the picture here. The delta pressure output on the FracHite log incorporates both the closure stress differences and the frac fluid hydrostatic head differences. If the delta pressures are reasonably close (less than 200 psi in general), then the zones can be treated together. If they are not, then several options exist to obtain an effective treatment.

The best option for optimizing fracture length is staging, or treating each group of similar delta pressures separately. This can sometimes be impractical due to the proximity of the zones to each other. Another complication enters if there would be a large number of stages required. Some Spraberry/Dean/Wolfcamp wells would benefit from an eight-stage frac but the maximum most operators will go with is four in most cases. If either of the above problems exist, then a less than optimal treatment must be accepted. The options that then exist are limited entry or ball sealers. Of the two, limited entry is used most often.

The concept of limited entry involves equalizing the pressure at the rock face by utilizing the friction pressure across the perforations. The friction pressure across the perforations is a function of rate, hole size, and frac fluid viscosity. Bundy's equation that incorporates these inputs to solve for the number of perforations in an interval is:

$$N = [Q^2 * p / .323 * d^4 * DP]^{1/2} \qquad (3)$$

where

N = number of perforations
Q = rate in BPM
p = specific gravity of fluid (water = 1.0)
d = perforation diameter (in.)
DP = fracture pressure difference between zone (psi)

Since the FracHite model deals strictly with the rock stress and assumes zero friction pressure drop, the DP in the above equation can come directly from the delta pressure output from the log. This method should not be employed where staging is economically practical, as the frac will still favor the path of least resistance. This path will be generally into the lower closure stress zones. If a zone is particularly attractive but at a higher stress level than surrounding zones, separate treatment should be considered.

A final consideration in multiple-zone treatments is the proppant settling phenomenon. The FracHite log can only predict where the fracture will be created, and this is not necessarily the same as where the fracture will be propped. A hydraulic fracture that is not propped open will be of limited benefit. Most zones that contain oil and water have the oil above the water, and it is this upper portion that will have the lowest sand concentration if the proppant settles. This occurs most often in low permeability formations where the fluid leakoff is slowest. If the option exists to create one large fracture or several smaller fractures within a stage, then the latter option should be considered. This can be achieved by limiting the delta pressure to the FracHite log specifications and keeping the intermediate barriers intact.

Several field examples of mutiple zone treatments follow.

EXAMPLE 5 - SAN ANDRES FORMATION, HOWARD COUNTY

An aquifer was below the pay (not seen on the log), and the operator desired to avoid it. The pay zones had different closure stress values, and staging would be required to treat all zones effectively. However, the lower zone had a weak barrier below it and it would be difficult to avoid the aquifer with a treatment of substance. The only viable option was limited entry, with a 300 psi delta pressure limitation. The major treatment was predicted to go in the upper perforations. The after-frac survey confirms both this and the height for a 300 psi delta pressure treatment.

EXAMPLE 6 - SAN ANDRES FORMATION, ECTOR COUNTY

Multiple zones were again involved. In this case, though, the delta pressure output indicated the zones were compatible. A 200 psi delta pressure treatment was recommended to stay in zone and to treat the upper and lower perforations effectively. The middle set of perforations was a marginal zone and a marginal treatment was acceptable. This pressure limitation would also allow the intermediate barrier to remain intact for proppant settling considerations. The after-frac survey confirms that the treatment stayed in zone, that the upper and lower zones received the best treatment, and that the intermediate barrier remained intact.

EXAMPLE 7 - CANYON FORMATION, IRION COUNTY

The operator had three main objectives. First of all, he desired to stay in zone and maximize frac length. Secondly, he desired to treat all zones effectively. Third, he desired to keep the proppant from settling out of the upper zone to the lower as the upper zone was more promising. Cement evaluation indicated a channel above and below the zones, and temperature decays were taken after the job to determine which zones were actually treated by the frac. The after-frac log indicates growth out of zone, but subsequent decay data indicated that the out of zone temperature indicators were caused by the channel and that the frac stayed in zone.

EXAMPLE 8 - CANYON FORMATION, IRION COUNTY

The operator desired to stay in zone, maximize frac length, and insure that the proppant was distributed evenly. The after-frac survey indicates that these objectives were accomplished.

PART II-ECONOMIC VALUE OF ACCURATE HYDRAULIC FRACTURE HEIGHT DATA

The previous examples illustrated that the FracHite log can predict the height of a hydraulic fracture treatment. This benefit in itself is not specific enough to warrant the expense of acquiring the data. The expense is only warranted if the log data allows the operator to increase the present value of the well in excess of the expense. The following case study illustrates where this was done.

The operator's objective was the San Andres formation in Ector County, Texas. The San Andres is a dolomite reservoir on the Central Basin Platform, ranging in depth from approximately 3500 to 5000 feet. It is a major contributor to the oil production in the county. Ector County is consistently one of the top 5 oil producing counties in the state. The majority of the wells completed in the San Andres are hydraulically fractured initially, with the remainder requiring frac treatments eventually to remain economically viable. In treating the San Andres, two major constraints exist. The lower San Andres is generally wet and has a strong water drive. If the hydraulic fracture contacts the water, then the well is generally ruined and the operator is forced to move uphole to the Grayburg or Queen formations or plug the well. On the other end, if the well is not stimulated effectively, the production suffers and valuable hydrocarbons are left in the ground. Most treatments are relatively small, with the majority having a volume of around 20,000 gal of fluid and 40,000 lb of sand. The sand is usually 20/40 mesh and the pumping rates vary from 10 to 20 BPM.

The operator began a drilling program in early 1985 and drilled three successful wells. Each well was treated with 20,000 gal of high viscosity crosslinked gel and 39,000 lb of 20/40 sand. This is considered to be the "standard" San Andres frac for the area. Open hole logs were run to determine the reservoir quality, but the FracHite log was not run. The initial production from the first three wells was between 70 and 186 BOPD with little water (5-16 BWPD). Well four was then drilled, and the open hole logs indicated that the reservoir quality was comparable to the first three wells. The well was opened up in the same zone as the first three, then hydraulically fractured with the same treatment. A comparison of the initial production data is shown in figure 2.

The initial well test after the treatment indicated that there were problems. There was no oil and a large amount of water. When the load was recovered, the well tested for 0 oil and 143 water. It was obvious at that time the lower San Andres aquifer had been contacted by the treatment, either through the rock or through a poor cement job. Cement evaluation indicated that it was most likely a combination of the two factors. After two months of attempting to salvage the zone, the decision was made to move uphole and complete in another zone.

On the next well in the program, a Long Spacing Sonic tool was added to the open hole logging program and the FracHite log was computed. It was immediately clear that there could be a fracture height containment problem if the standard San Andres treatment was used. On the wells that were fractured hydraulically following this unsuccessful treatment, the design was changed to a less viscous gel, smaller job, and a lower rate. Twelve wells followed, all with FracHite log data. Two of the wells were not hydraulically fractured since their unfractured production was near the field allowable. The wells that were fractured received tailored treatments, with the job size ranging from 10,000 to 20,000 gal pumped at rates between 10 and 20-BPM. To date all completions have been successful.

A representative well out of this latter group was chosen. The FracHite log for this well is shown as example 6 in the preceding section. The after-frac survey was also shown to verify the FracHite log's accuracy. From this data and the frac service company design parameters the created fracture geometry can be inferred. This geometry can then be entered into a reservoir model for hydraulically fractured wells and a decline curve constructed using the actual well test data as a basis. The reservoir model utilizes the Agarwal method for hydraulically fractured reservoirs. The hydraulic fracture geometry was generated by the service company using a modified Geertsma-Deklerk two dimensional model. As a comparison, the same steps are taken for the same well with the "standard" treatment parameters substituted for the actual treatment parameters. The "standard" treatment geometry is entered into the Agarwal model, using the same base reservoir conditions. A production comparison is then made to illustrate the specific benefits of tailoring the job to the specific well.

Well Data

Zone	San Andres
Depths Perforated	4173' - 4220'
Lithology	Dolomite
Porosity	12%
Permeability	.5 md
Poisson's Ratio	.29
Shear Modulus	3.4
Young's Modulus	9
Reservoir Pressure	1930 psi
Reservoir Fluid Viscosity	1.5 cp
Initial Treatment After Perforating	2500 gal. NEFE acid
Initial Test (1st week average production before frac)	27 BOPD
Initial Potential Test After Frac	138 BO/0 BW/70 MCF IP

Figure 4 compares delta pressure vs height for this well, taken from the Frachite log.

Frac Design Comparison

	"Tailored Job"	"Standard Job"
Volume	10,000 gal	20,000 gal
Rate	8 BPM	15 BPM
Viscosity	65 cp	200 cp
Frac Height	63'	140'
Frac Length	400'	270'

Economic Comparison

5-year cumulative oil (barrels)	70,418		59,970
75% NRI barrels, discounted 10% **	45,123		38,400
Well present value at $25 oil	$1,128,075		$ 960,013
Well present value at $20 oil	$ 902,460		$ 768,000
Well present value at $15 oil	$ 676,845		$ 576,000
Present value difference ($25)		$ 168,062	
Present value difference ($20)		$ 134,460	
Present value difference ($15)		$ 100,845	
Logging cost difference		$ 4,270	
Net present value of log data ($25)		$ 163,792	
Net present value of log data ($20)		$ 130,190	
Net present value of log data ($15)		$ 96,575	

** Discounted Barrels * NRI * Flat Price = Present Value

Figure 5 illustrates the present value of the well's production with the two different treatments. Three oil price scenarios are considered as well, with the price held flat over the five year period. The cash flows are discounted to the beginning of each year. The present value comparison assumes that the operator has a 75% net revenue interest and a 10% alternative investment rate. Gas production is not considered. The savings from running the smaller frac job is not considered, as in many cases the FracHite data supports running larger jobs. This also assumes that the larger, less efficient job avoided the water zone below. If the frac hit the water then the NPV of the investment becomes the present value of the pay zone less the logging cost. The comparison illustrates that even with a "successful" treatment (one that avoided the water) and a pessimistic oil price, the net present value of the log data is $96,575.

This clearly illustrates the specific benefits of tailoring the job to fit the well, made possible by combining the FracHite log inputs with the frac service company expertise. At this point it might be proposed that the "standard" treatment be revised along the lines of the "tailored" treatment. This is not recommended, as offset wells can have significant differences in the delta pressure vs. height relationship. Figure 6 illustrates the delta pressure vs. height relationship for three direct offset wells, and figure 7 illustrates a plot of frac length vs production for the "tailored" well. It is clear from this data that the same treatment pressure on all wells would yield different heights, and conversely different lengths. A case is thus made for tailoring the treatment to the well whenever possible, using the FracHite log inputs as an essential starting point.

PART III - SPRABERRY / DEAN HYDRAULIC FRACTURE ORIENTATION

In the early days of hydraulic fracturing, there was controversy over whether the treatments were in the vertical or horizontal plane. It is now accepted within the industry that the great majority of the hydraulic fractures are vertical. It is also generally accepted that the hydraulic fracture will assume a two-wing pattern with a definite orientation, and that this orientation will be dictated by the path of least resistance. Very rarely will the hydraulic fracture extend radially from the borehole. It will always assume a compass direction, be it N-S, E-W, etc. Knowledge of this compass direction is critical to well location (figure 8).

Various methods have been employed to obtain hydraulic fracture orientation, including pressure interference tests, surface geophones, borehole seismic, graviometers, tilt meters, and mineback experiments. All these methods have limitations and are effective only in certain areas. Where these are not economically practical the orientation must be inferred from other indicators. Two such indicators are natural vertical fracture orientation and borehole ellipticity. The minimum horizontal stress component can be assumed to be perpendicular to the natural fractures and to the long axis of an elliptical borehole (figure 9). This technique was employed in reference 5 to map the stress orientation in the Cotton Valley formation of east Texas.

With Dual Dipmeter data (figure 10), the orientation of natural fractures and the borehole ellipticity can be determined to within two degrees of azimuth. The FILMAP presentation (figure 11) is used to map the dominant natural vertical fracture trend around the borehole and give a 360 degree view of the borehole (figure 12). The Dual Dipmeter monitor log with oriented dual calipers (figure 13) is used to map the long axis of the borehole. The results are mapped on figure 14 with the arrows corresponding to the dominant natural fracture orientation. In all cases the natural fracture axis corresponded to the long axis of the borehole when the hole became elliptical.

From figure 14, it is obvious that the central Midland County wells have a strong easterly component. The majority of the vertical fractures observed were between N75°E and N85°E. In northeastern Midland County and southern Martin County the fracture trend exhibited a more northeasterly component. The majority of the vertical fractures there were oriented between N60°E and N75°E. This data should be considered in designing drainage patterns in these areas. With the trend toward 80 acre infill development in the Spraberry trend, this data will become increasingly critical, where it may not have been with the original 160 acre spacing. More data points are needed to further validate these results, as the study covered only a small portion of the Spraberry trend.

CONCLUSIONS

The FracHite log has clearly demonstrated the ability to predict the vertical extent of hydraulic fractures in the Permian basin. This data is valid in both single-zone and multiple-zone applications. It is also valid in both carbonate and sandstone reservoirs. The FracHite data is critical to tailoring the hydraulic fracture treatment to fit the individual well. Tailoring the hydraulic fracture treatment to fit the individual well can be critical to the economic performance of the well.

The eight button Dual Dipmeter log can provide accurate data on natural fracture orientation and wellbore geometry. This data can be critical to designing the optimum drainage pattern for a field. This is becoming more critical with the trend toward infill drilling programs.

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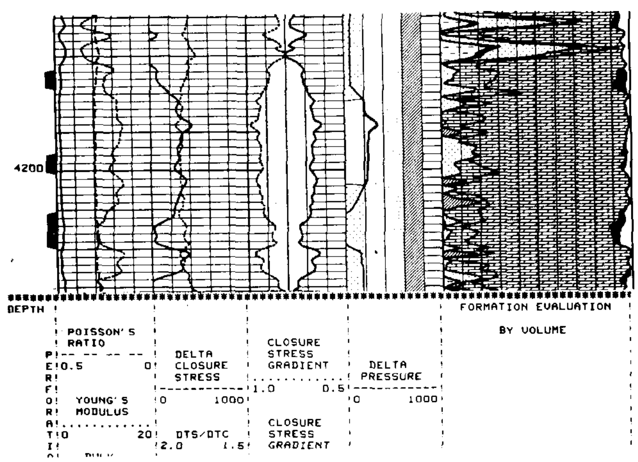
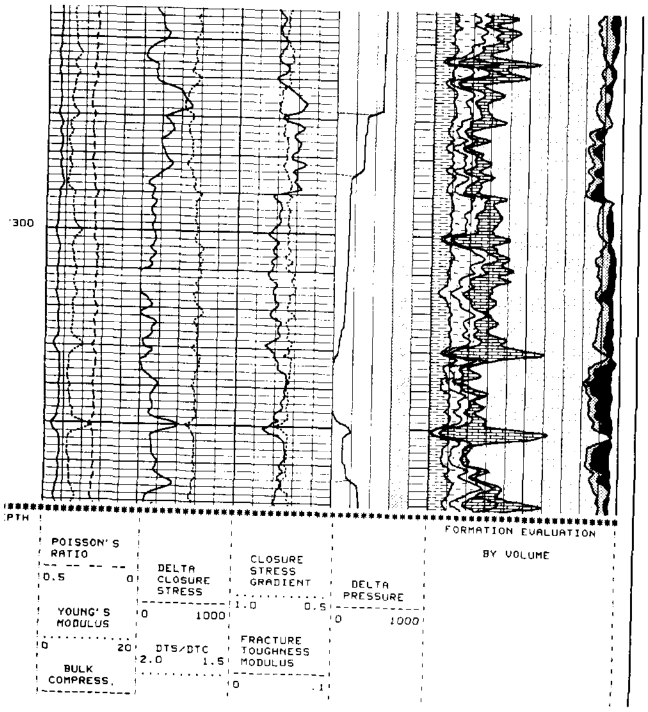
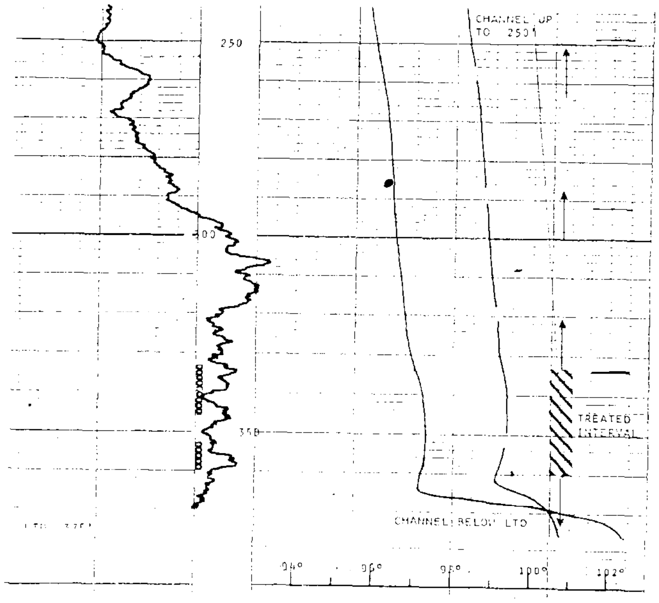


Figure 1—The FracHite log

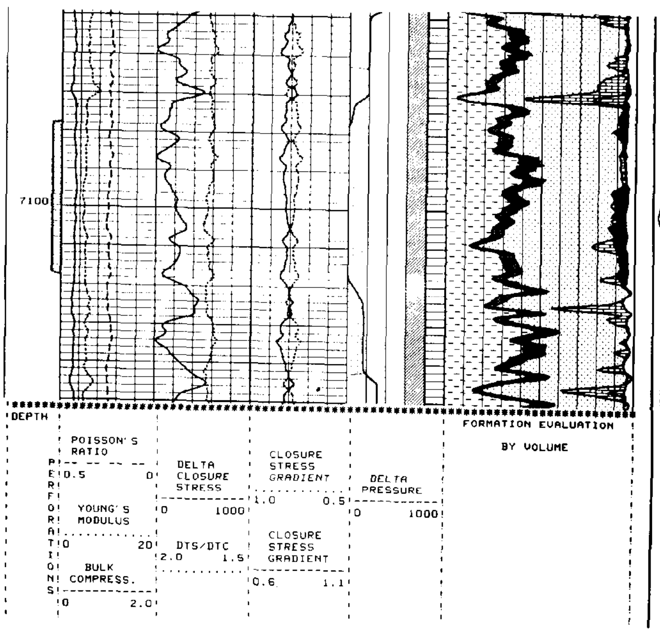


FracHite log



After-frac survey

Example 1



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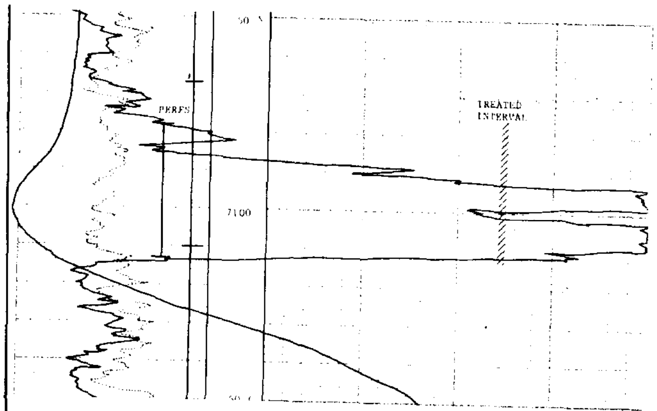
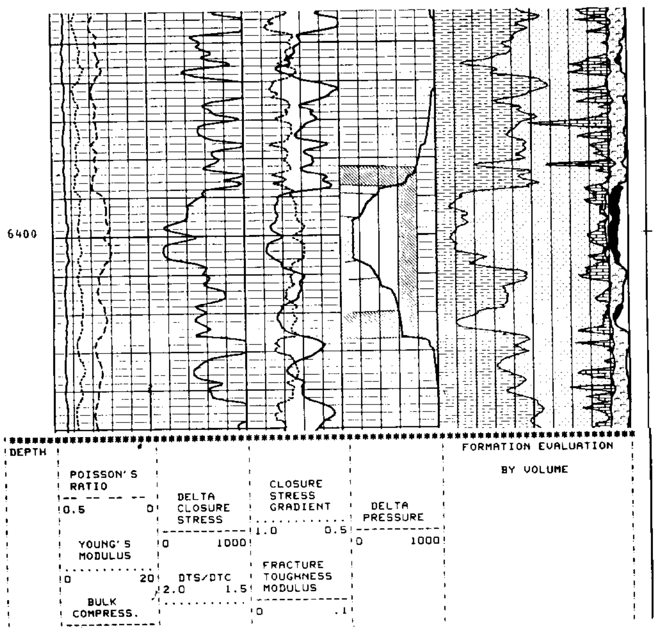
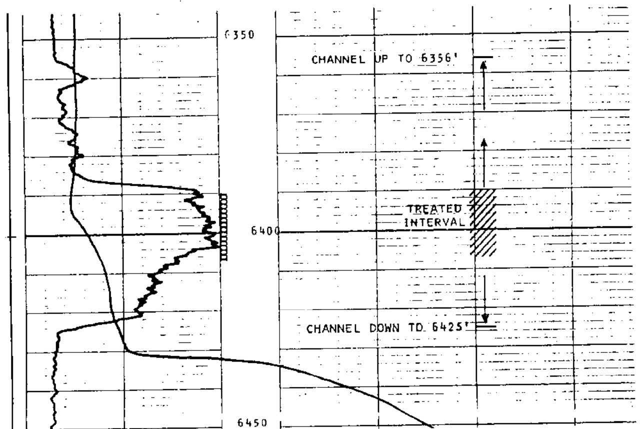


After-frac survey

Example 2

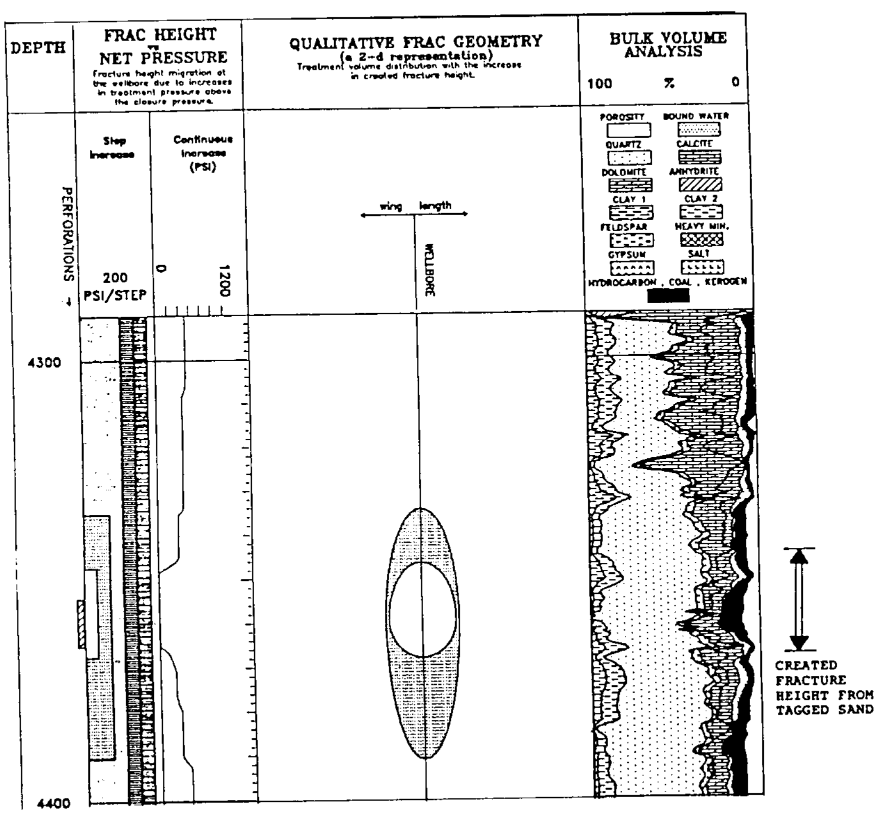


FracHite log

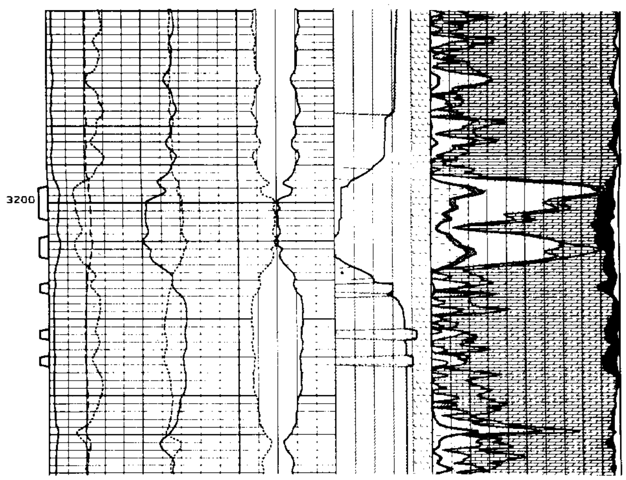


After-frac survey

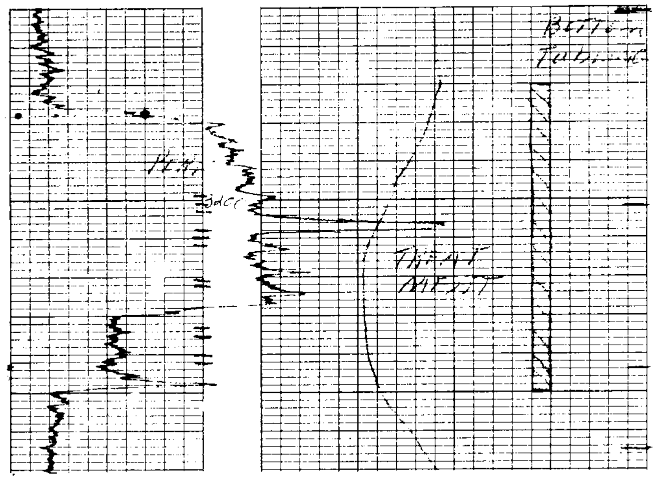
Example 3



Example 4

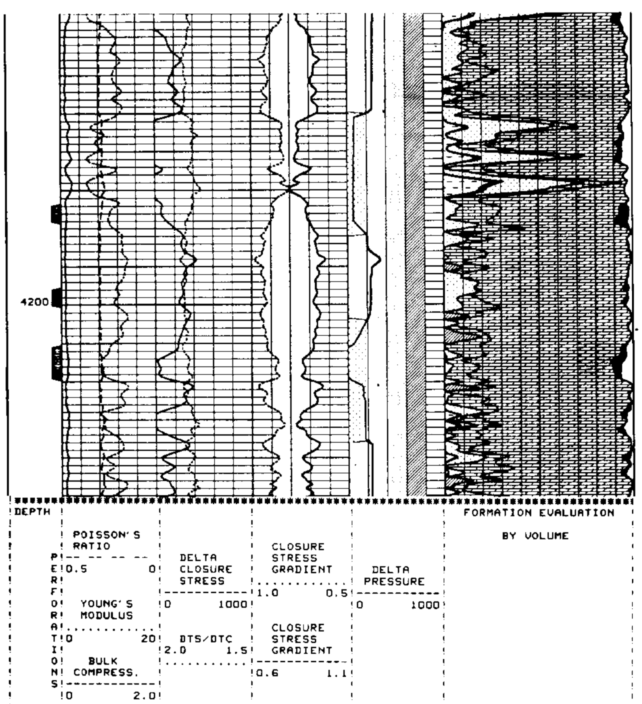


FracHite log

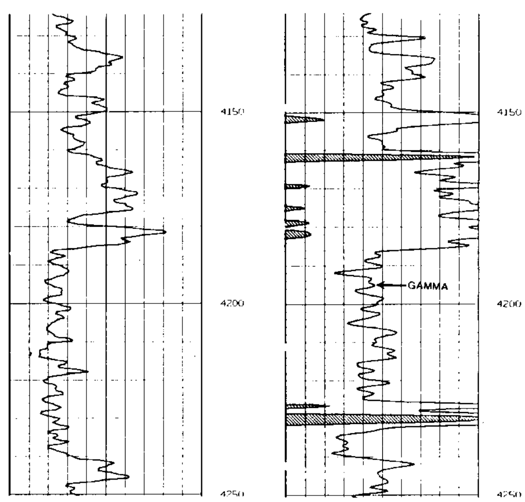


After-frac survey

Example 5

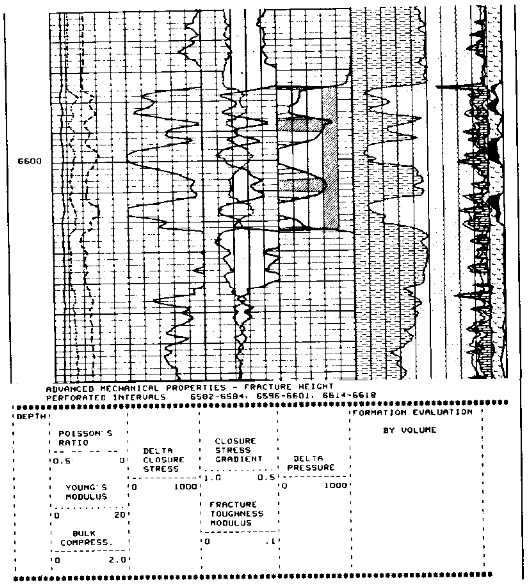


FracHite log



After-frac survey

Example 6



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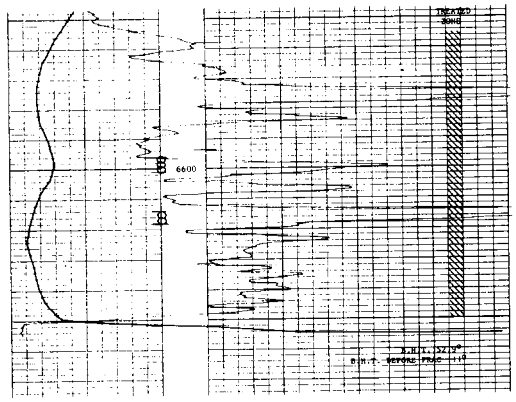
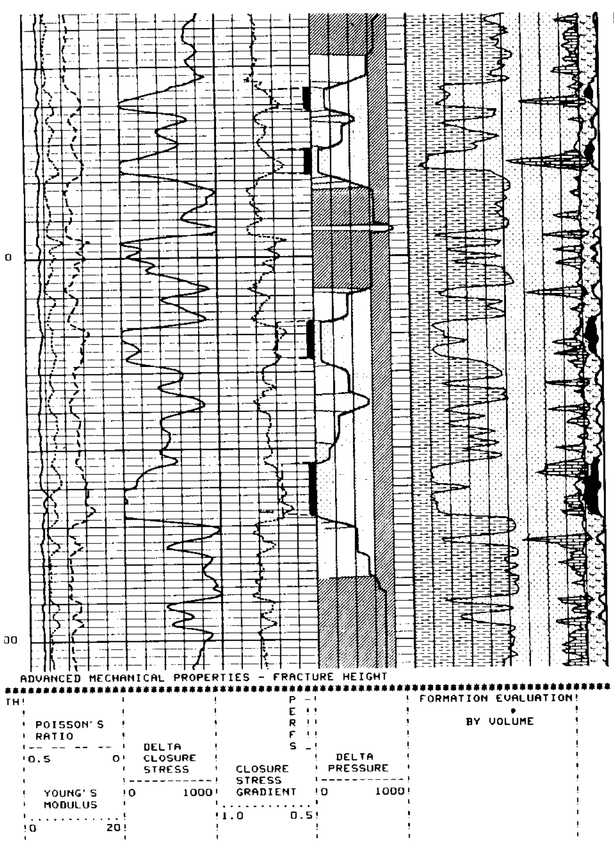
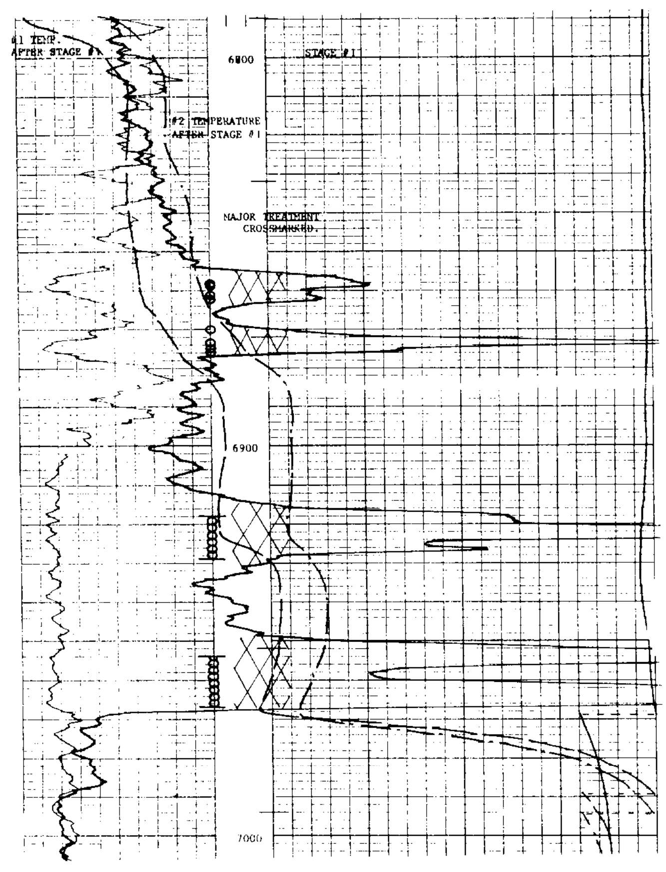


After frac survey

Example 7



FracHite log



After-frac survey

Example 8

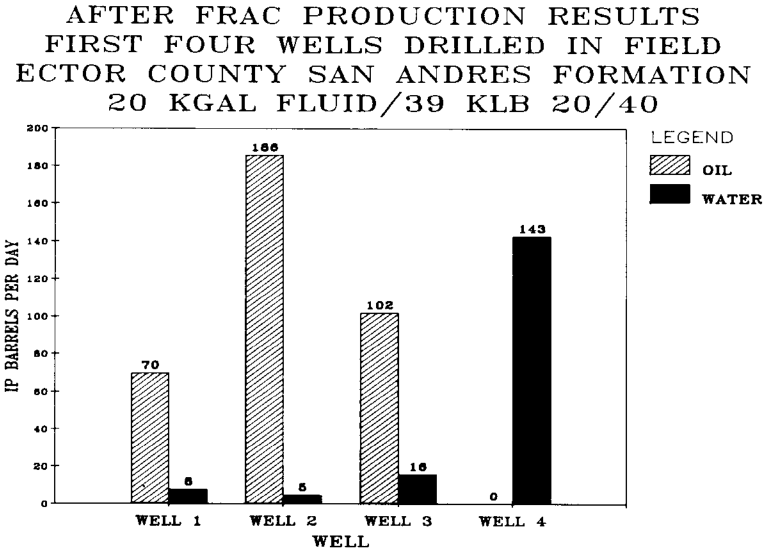


Figure 2

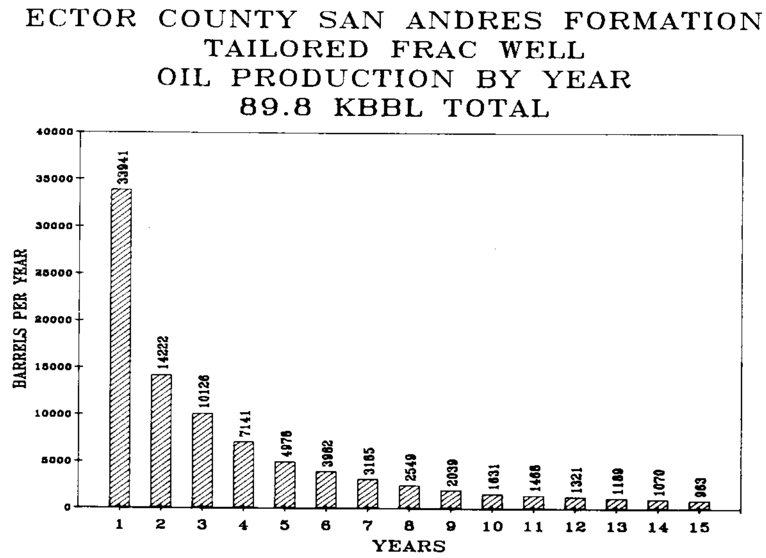


Figure 3

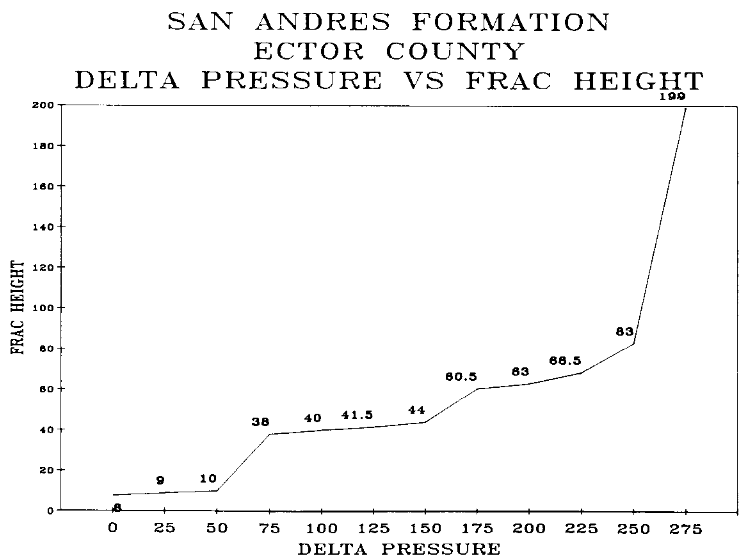


Figure 4

ECTOR COUNTY SAN ANDRES FORMATION
TAILORED FRAC vs STANDARD FRAC
PRESENT VALUE OF OIL PRODUCTION
75% NRI/10% INTEREST

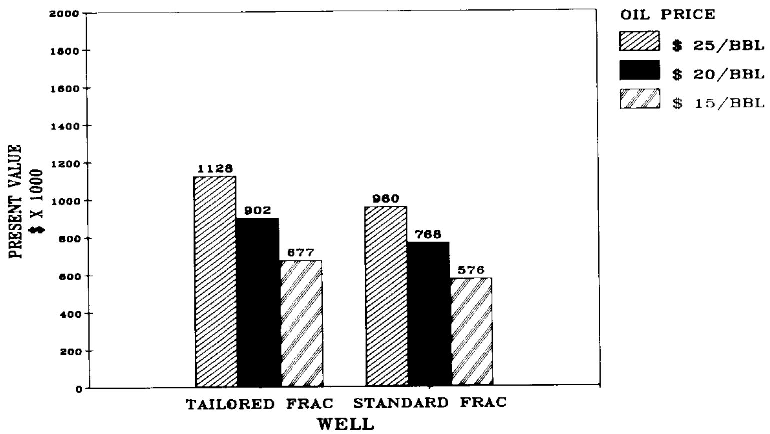


Figure 5

ECTOR COUNTY SAN ANDRES FORMATION
NET PRESENT VALUE OF FracHite DATA
(PV DIFFERENCE – LOGGING COST)
75% NRI/10% INTEREST

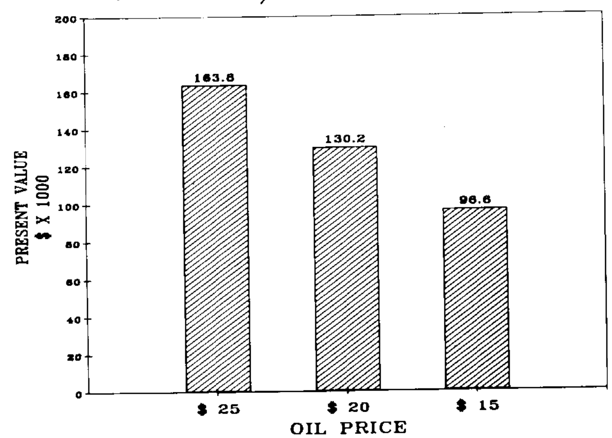


Figure 5a

SAN ANDRES FORMATION
ECTOR COUNTY
DELTA PRESSURE VS FRAC HEIGHT
3 DIRECT OFFSET WELLS

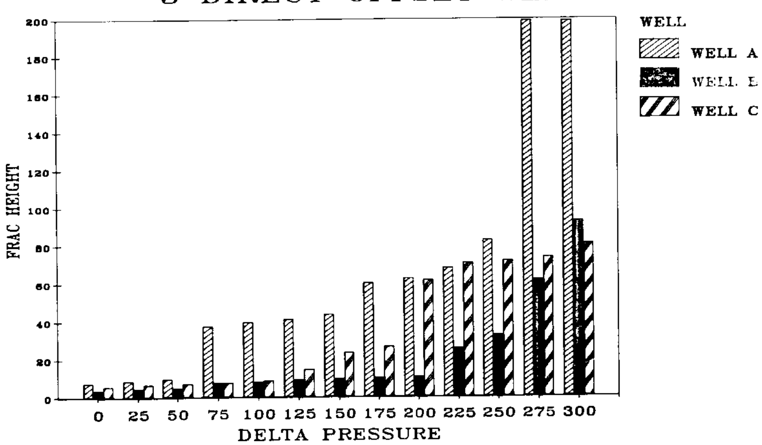


Figure 6

SAN ANDRES FORMATION
ECTOR COUNTY
5 YEAR OIL PRODUCTION vs FRAC LENGTH
10 KGAL FLUID/15 KLB SAND

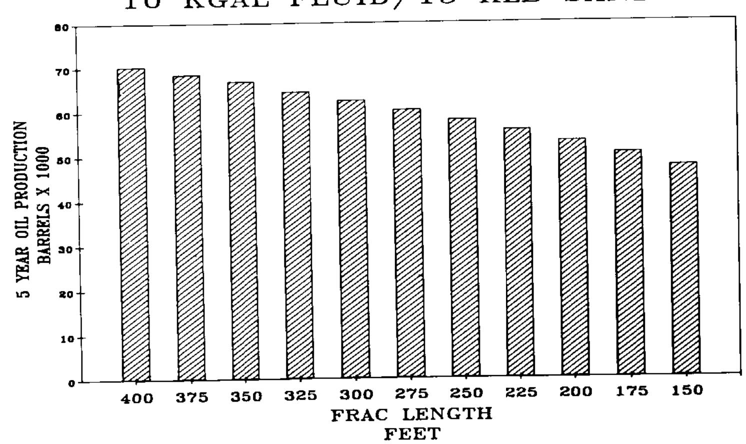
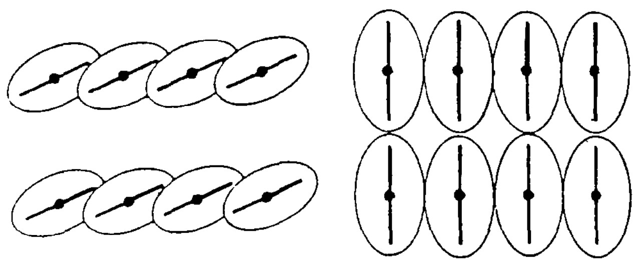


Figure 7



Optimum Recovery
Inefficient Recovery

Figure 8

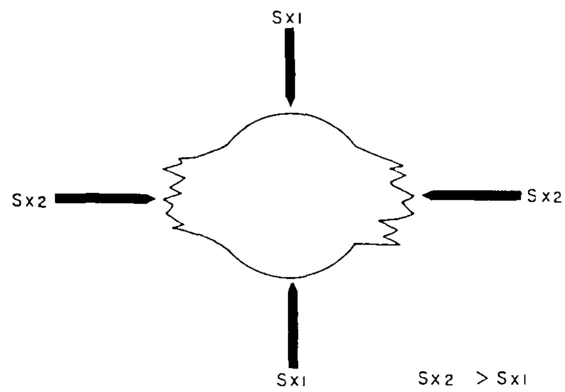


Figure 9

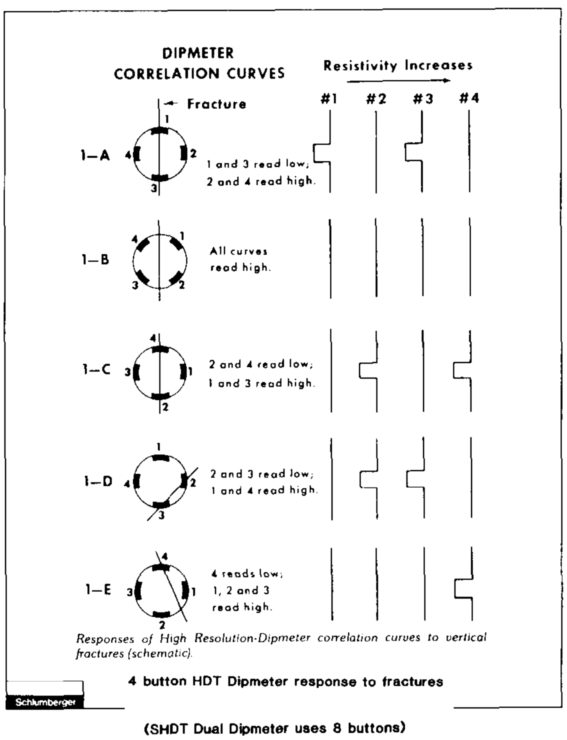


Figure 10

FILMAP - Dual Dipmeter Fracture Detection Log

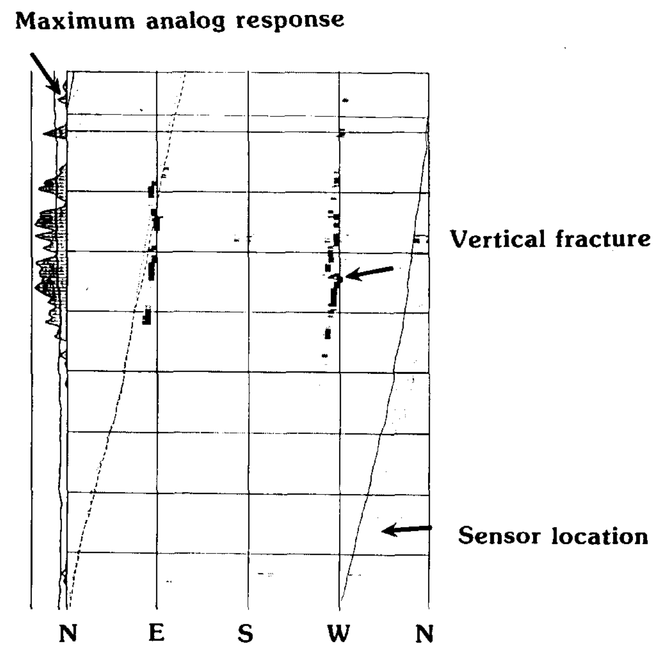
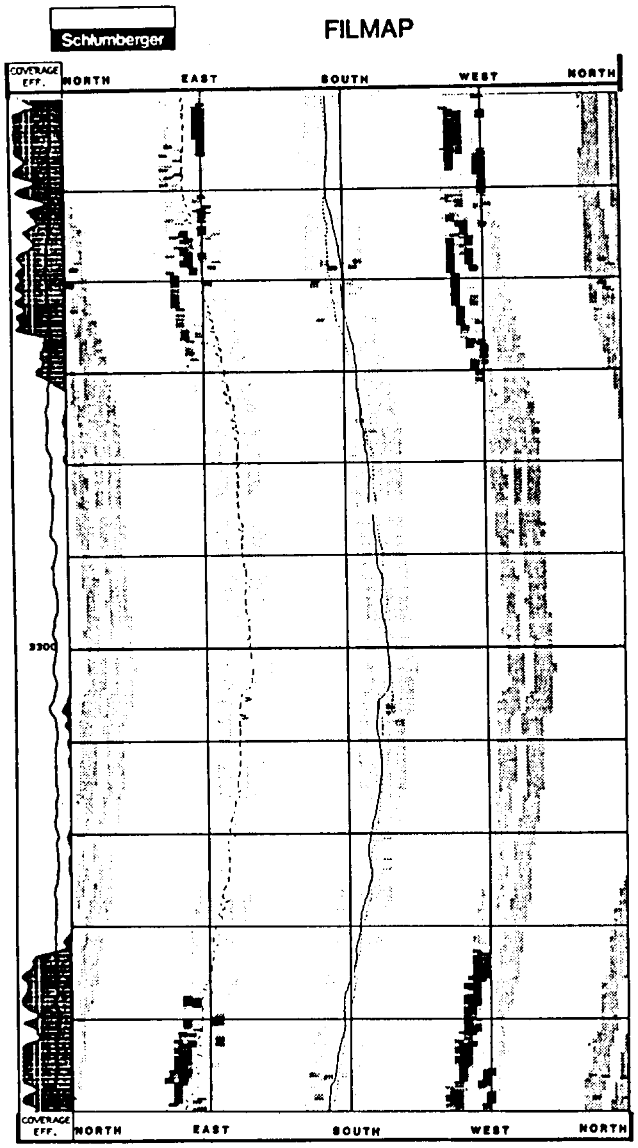


Figure 11


Schlumberger
FILMAP
COVERAGE EFF.
NORTH
EAST
SOUTH
WEST
NORTH
3300
COVERAGE EFF.
NORTH
EAST
SOUTH
WEST
NORTH

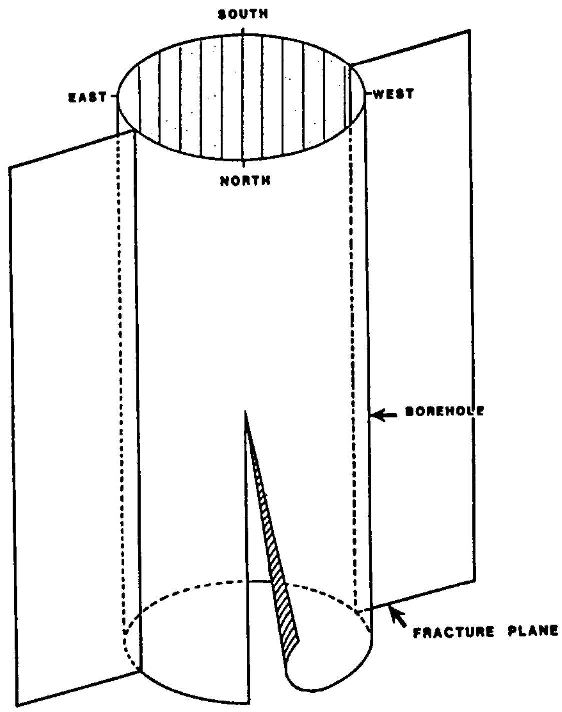
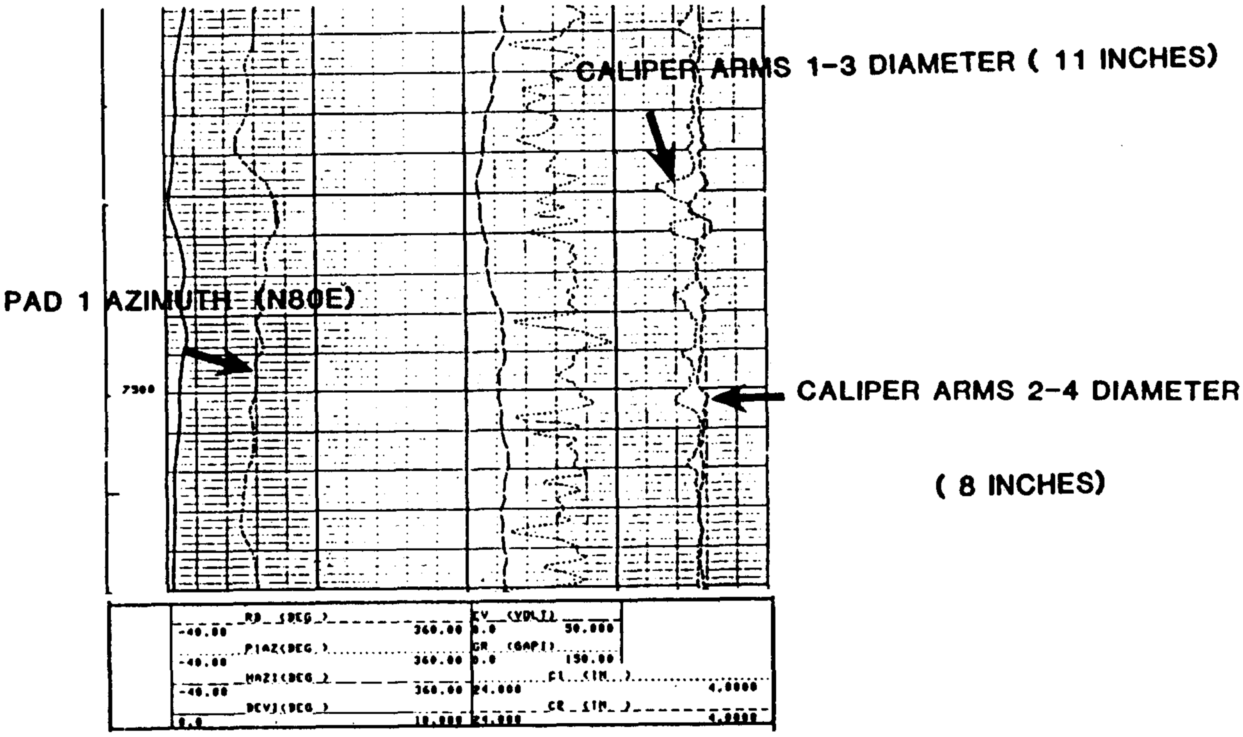
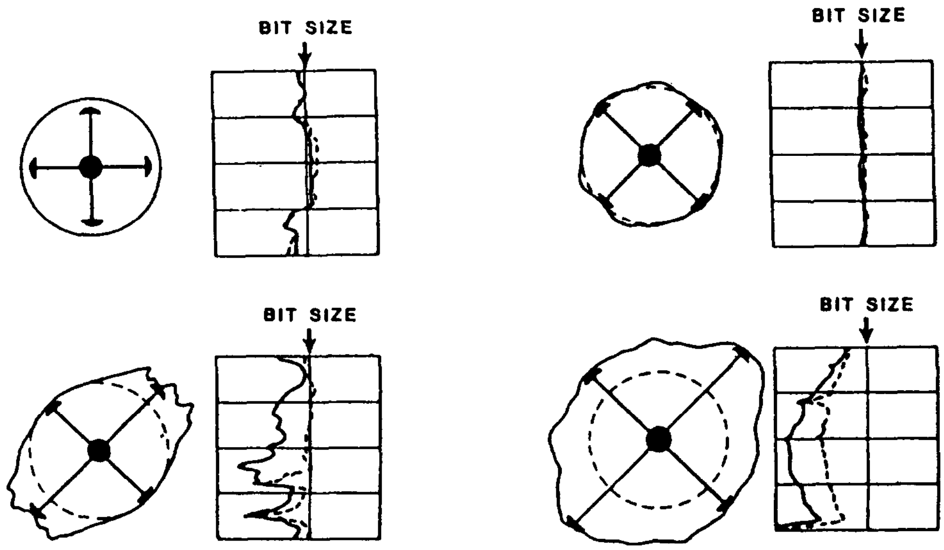

SOUTH
EAST
WEST
NORTH
BOREHOLE
FRACTURE PLANE

Figure 12





POSSIBLE CONDITIONS OF BOREHOLE SHAPE

Figure 13

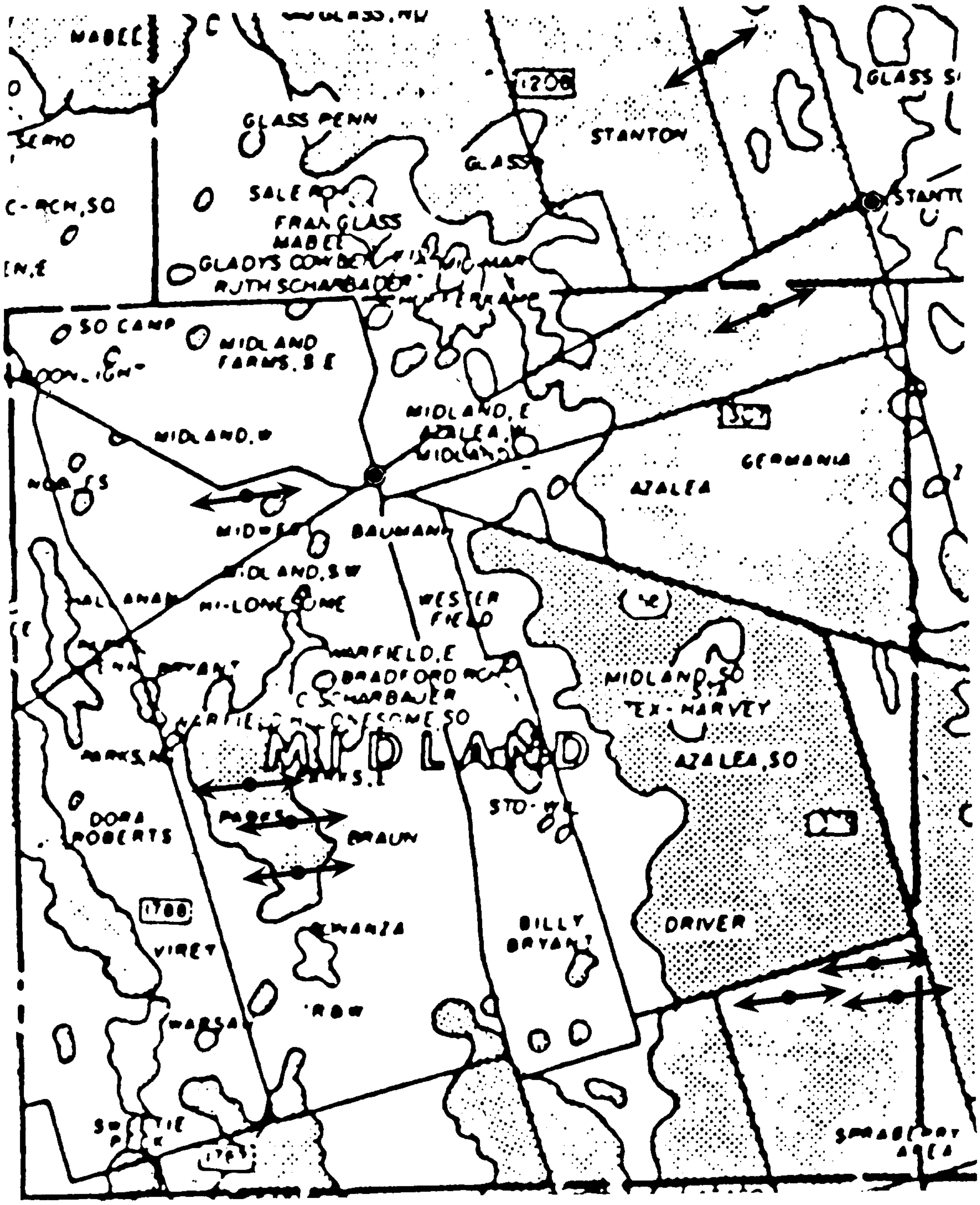

STANTON
GLASS PENN
MIDLAND,E
MIDLAND,W
MIDLAND,SO
AZALEA
AZALEA,SO
MIDLAND
DORA ROBERTS
BILLY BRYANT
DRIVER
BRAUN
1788

Figure 14