DETERMINING INJECTION PRESSURE LIMITS WITH WIRELINE AND TESTING INPUTS

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ABSTRACT

A matter of concern in most secondary recovery projects is control of the movement of injected fluids. If the injection pressure exceeds the fracture gradient of the confining layers of rock, the injected fluids will not be optimally placed. Historically, operators have seen evidence of exceeding fracture gradients in pay zones using Hall plots, fall off tests, square root of time plots or step rate tests. All these methods require fracture stimulation of the rock and though they describe the pay zone stresses adequately, they lack data on the boundary rock. Tracer surveys can tell when the fluids have migrated out of zone. Unfortunately, this data is obtained after the fact. Determining the injection pressure limits prior to fracturing out of zone is preferred.

With developments in in-situ stress measurements, this data is now available in a timely manner. The methodology proposed is to determine a continuous hydraulic fracture gradient in the wellbore using full wave sonic data and formation pressure data. This has been accomplished on over 700 producing wells since 1984 to control the hydraulic fracture treatment. Recently, this technology has been expanded to include water injection wells to control the injection process. A discussion of the methodology used follows along with a field example.

INTRODUCTION AND BACKGROUND

All injection wells in secondary or tertiary floods have the potential to induce fractures if the injection pressure exceeds the fracture gradient of the reservoir rock. Sometimes this is done intentionally when the rock is of poor quality and sufficient injectivity could not be achieved without fracturing.[1] An example of economics dictating that the injection pressure exceed the fracture gradient is when a target date is to be met for a certain reservoir pressure, such as the minimum miscibility pressure (MMP) in preparation for CO_2 flooding. This has been the case for several of the San Andres dolomite floods of west Texas, where the formations are not deep enough to handle the necessary injection rate without fracturing.

Of course, there are some well known disadvantages to injecting over fracture pressure which must be weighed: 1) A fracture in the injector - producer direction results in early breakthrough and subsequent large volumes of produced flooding agent; 2) If the fracture is 1/4 the distance between the injector and producer, the areal sweep efficiency at breakthrough could be reduced by 60%, 1/2 the distance by 72%.[2] 3) The fracture will increase the likelihood of crossflow between previously insulated reservoir layers, adversely affecting the vertical sweep efficiency;[3] 4) A waterflood induced fracture may not heal completely after the targeted pressure is achieved and thus carry the sweep efficiency problems over to the tertiary stage.

Perhaps the most serious problem occurs when the injection pressure exceeds the fracture gradient of the boundary rock. This situation is not dealt with in common practice because the induced fractures are assumed to stay within a certain zone as determined by bed boundaries. However, the absolute strength of these boundaries is seldom determined. The multi-rate or step rate test is the most common method for determining injection pressure limits but it stops after the fracture pressure of the reservoir rock is reached. A step rate test could be applied to the boundary rock but it would require physically fracturing the boundary rocks which is not a desirable situation in an injection well.

In stimulating wells with hydraulic fracture treatments, knowledge of the rock elastic properties and in-situ stress distribution of both the reservoir rock and its confining layers is critical to determining the induced fracture geometry. The FracHite* log has demonstrated the usefulness of using dynamic measurements of elastic properties to predict fracture height migration.[4] The same approach should be applied on injection wells so that the injection pressure at which the confining layers of rock break down is never reached.

This paper presents a new application of the FracHite log for determining at which injection pressure the boundary rock will break down as well as each individual layer within a flooded interval. The method can be applied to either new wells or to already cased wells prior to fractures being induced.

THEORY OF MEASUREMENT

The theory behind the FracHite log is discussed thoroughly by Newberry, Nelson and Ahmed in references (5) and (6). A brief summary is provided here. The heart of the FracHite model is the Borehole Compensated Sonic tool shear and compressional wave slowness (a velocity calculated from travel time), measured with either the Long Spaced Sonic (LSS*) tool or the digital Array Sonic* tool. (see Fig 1 and 2). 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. The dynamic definition of Poisson's ratio is:

$$v = [\ 0.5\ (Vc/Vs)^2 - 1] \tag{1}$$

where

Vc = compressional slowness
Vs = shear slowness

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The fracture gradient is a direct function of Poisson's ratio, integrated bulk density pb (over burden pressure) and pore pressure (Pp).

$$F.G. = (v / 1-v) (pb) + [1- (v / 1 - v)] (Pp) / Depth \qquad (2)$$

This equation is based on the Transversely Elastic Model[5] and is critical in predicting fracture height.

Simonson et al.[7] has presented fracture equations that relate wellbore injection pressure to in-situ stress distribution (fracture gradient), material properties and fracture height migration. The successful use of the Simonson et al. concept to calculate variable height at the wellbore has been reported by Voegle et al.[8] and Settari[9]. Ahmed[10] has shown how this concept can be applied to the hydraulic fracturing models of Geertsma and De Klerk[11] and Perkins and Kern[12] for design of optimized hydraulic fracture treatments. The two most common models are shown in Fig 3. Without prior knowledge of the elastic parameters and the fracture gradient distribution, these models will not be effective and the optimum placement of fluids will not be attained. (see Fig 4)

The logical method to determine the fracture gradient has always been to actually fracture the formation in the pay zones and boundaries and measure the fracture pressure of each. This is called a micro-frac. It is accomplished by pumping a small volume of fluid into the formation at low rates and observing the breakdown (Pb), fracture propagation (Pf) and shut in instantaneous (ISIP) pressures. (see Fig 5) The ISIP is the pressure at which the fracture closes and is generally used to map the fracture gradient distribution. The main problem with this technique is that several tests need to be made in both pay and boundary zones which become expensive ($20K - $30K). There are other techniques for obtaining ISIP's, such as from acid jobs, mini-fracs and actual frac jobs but like most micro-fracs only the pay zone is evaluated.

The FracHite log overcomes the limitations previously discussed. The principle output is a continuous frac gradient distribution over both the pay zones and boundaries. (see Fig 6) Figures 7 and 8 are plots from Whitehead, et al. 1987[13] of log derived vs micro-frac derived in-situ stress measurements showing good to excellent agreement.

The only variation necessary to apply the FracHite model to an injection well is in assigning the pore pressure (Pp) in Equation 2 above from:

a) well test data of $\overline{P}$ for the reservoir formation and from;
b) virgin formation $\overline{P}$ for the boundary formation.

In normal applications the pore pressure value can be either assumed or measured, with the result being either a relative or actual frac gradient. This may differ in areas where tectonic activity is significant. However, in the Permian Basin which is tectonically inactive, the actual fracture gradient during stimulation is very close to the log derived value when a measured pore pressure is available, (see Fig 9) If the pore pressure is assumed, the FracHite log will predict height vs net pressure only when the propagation pressure is determined at the time of fracturing. Since this is not practical for the injection well application, pore pressure must be a measured value. Sources for formation pressure from well test data are:

* Repeat Formation Tester (open hole) or
  (cased hole when casing = 7" or)
* Drill Stem Test (open hole)
* Drill Stem Test (cased hole)
* Slickline Test Fall-Off (cased hole)
* Wireline Test (cased hole) (SPRO, TRAP)

This is a subtle but important difference in the application of the FracHite model to injection wells. The pressure variations between reservoir and boundary rock can be large in a waterflood. The variations may even be large between different reservoir layers. The importance of this difference comes to light with an industry "rule of thumb" that says, "The younger the injection well the lower the parting pressure." As an injector becomes older, it can withstand higher injection pressures without fracturing the rock. This phenomenon becomes obvious when considering the direct relationship between pore pressure and fracture gradient in Equation 2. Therefore, the critical time in an injector's life is when it is newly drilled or newly converted.

EXAMPLE

Two new water injectors were drilled in a Mississippian formation under waterflood in Borden County, Texas. Open hole logs were run to obtain fracture gradient distribution from the FracHite log. The logs included Long Spaced Sonic for shear and compressional slowness, the Litho-Density tool for bulk density, lithology, and porosity, and the Dual Dipmeter to establish the natural fracture orientation. Fig 10 is the FracHite log where the "closure stress gradient" as presented in track 3 is the in-situ stress vs. depth or fracture gradient which is calculated by the Transversly Elastic Model. The "delta pressure" output in track 4 translates the difference in closure stress between the pay zone and boundaries into actual fracture pressure. Delta pressure is the difference between the propagation pressure at the wellbore and the propagation pressure at the tip of the fracture, which shows the limit to Pf which the injection pressure must not exceed in order to keep the fluid in zone. In this example 600 psi over frac pressure was decided to be the limiting injection pressure.

Both wells have fracture gradients as determined by fall off tests to compare to the fracture gradient from FracHite. (see Fig 11, Fig 12 and 13)

CONCLUSIONS

The FracHite log has demonstrated that it can determine the fracture gradient of the reservoir and the boundary rocks in tectonically relaxed areas when direct measurements of reservoir pressure are available. This method can now be applied to injection wells to determine the pressure limits of the boundary rocks without physically fracturing the rock.

ACKNOWLEDGMENT

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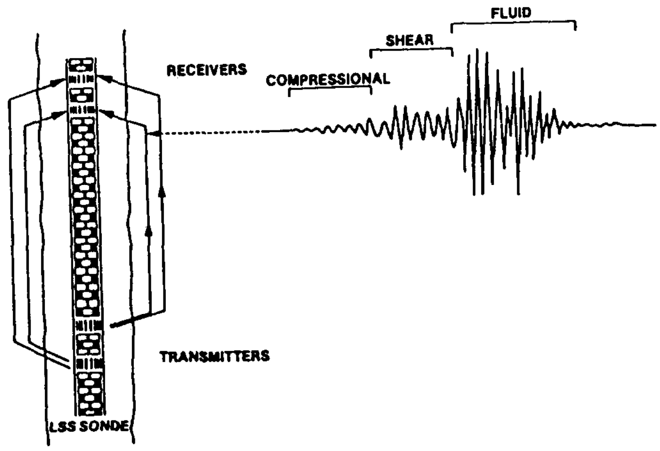


Figure 1 — The separation of the shear and compressional waves with the Long Spaced Sonic tool

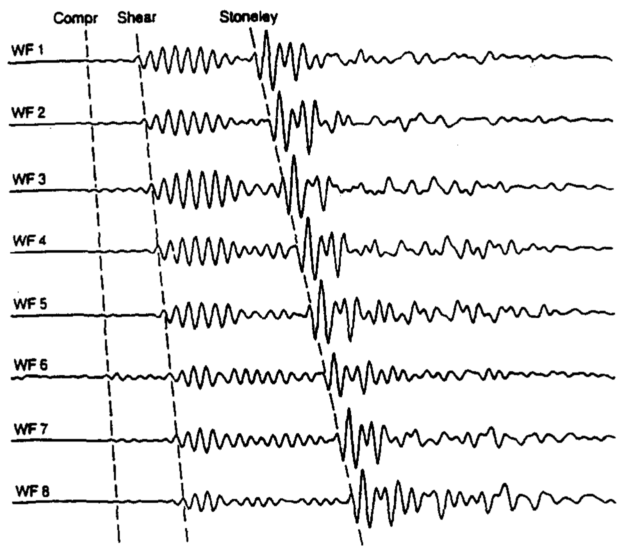


Figure 2 — Array-Sonic waveforms in open hole. The Array Sonic is also the best tool to obtain compressional and shear velocities behind pipe.

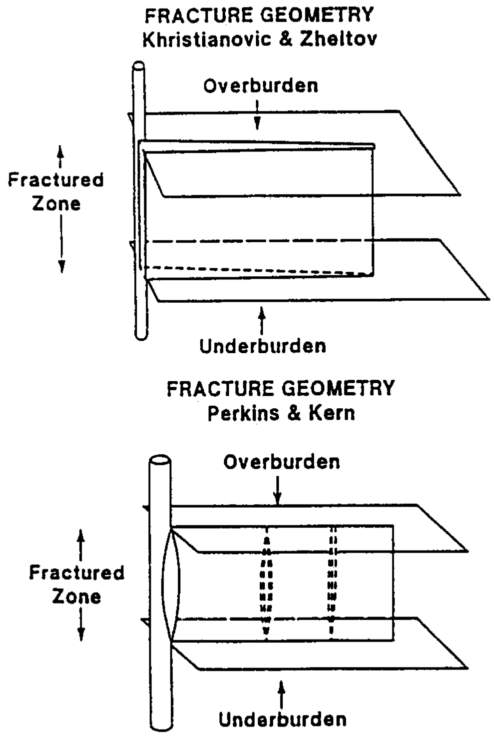
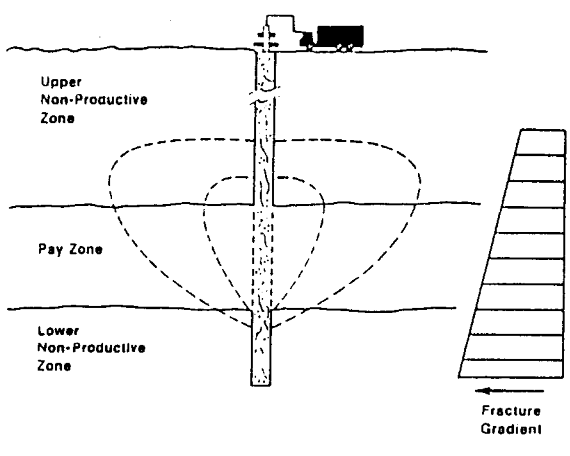


Figure 3 — Currently used hydraulic fracturing models



• Severity of Fracture Migration

Figure 4 — A possible consequence of not knowing the fracture gradient distribution

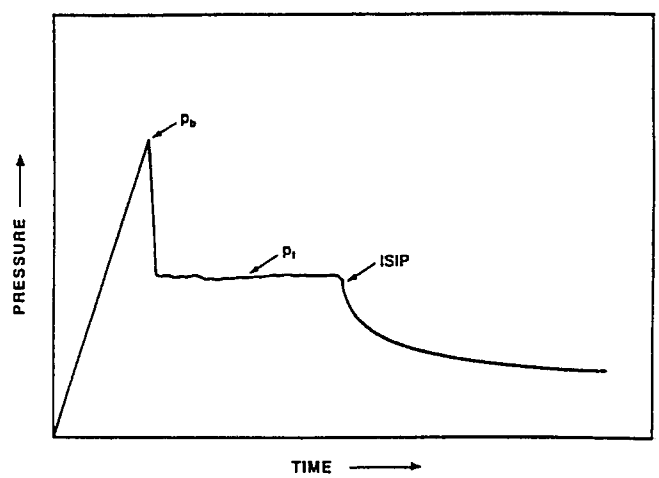


Figure 5 — Nolte-Smith plot of an idealized micro-frac

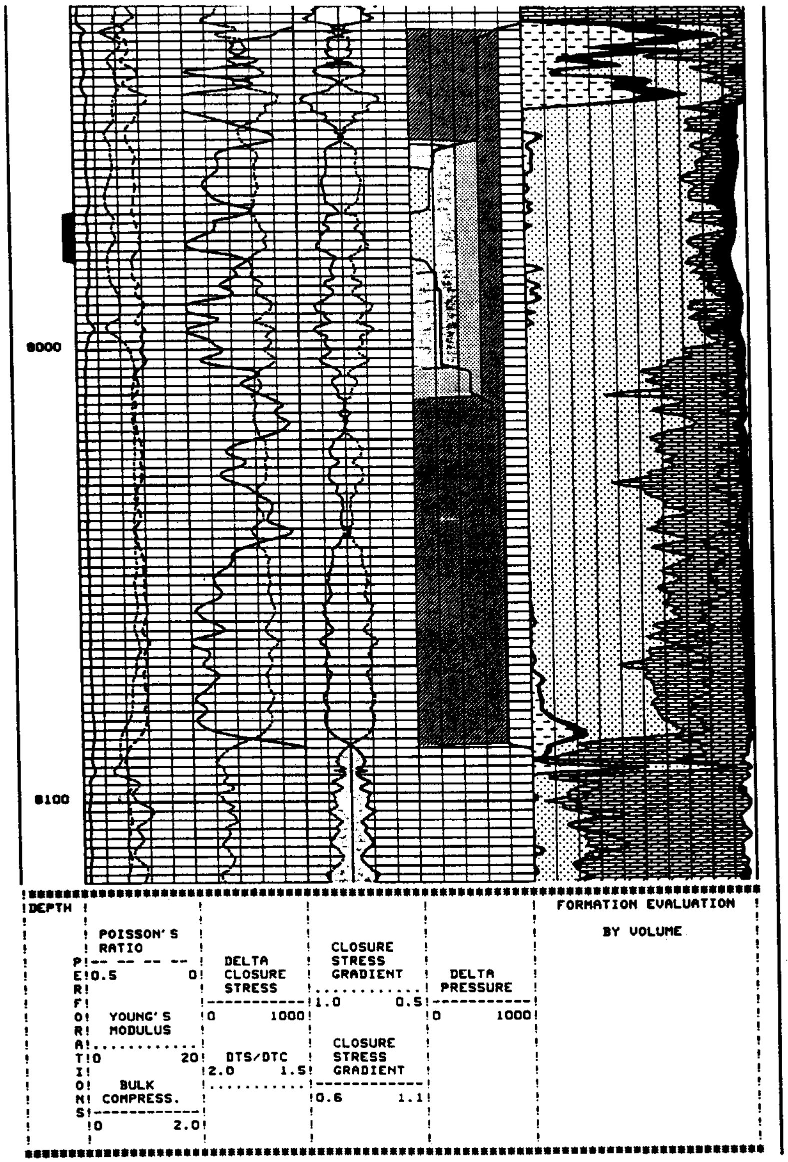


Figure 6 — FracHite presentation of fracture gradient as closure stress gradient in track 3

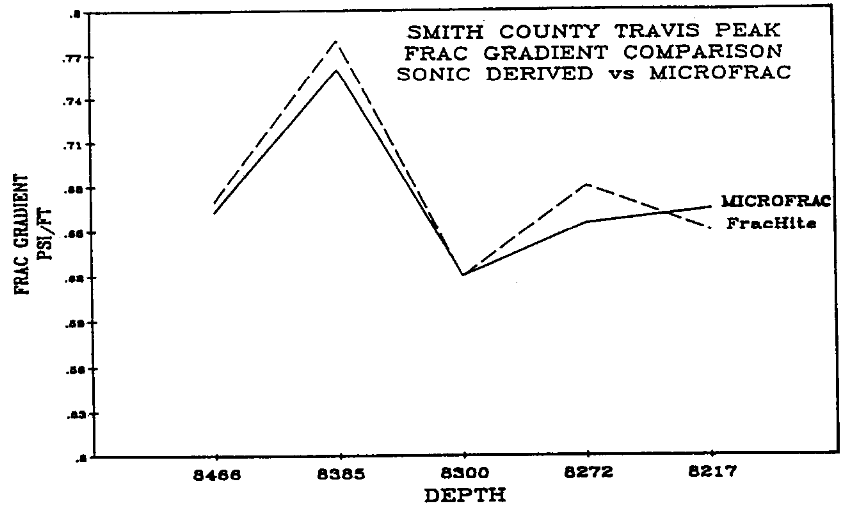


Figure 7 — Micro-fracs were performed on five different zones: four reservoirs and one boundary shale at 8385 ft. The FracHite gradients were calculated prior to the micro-fracs.

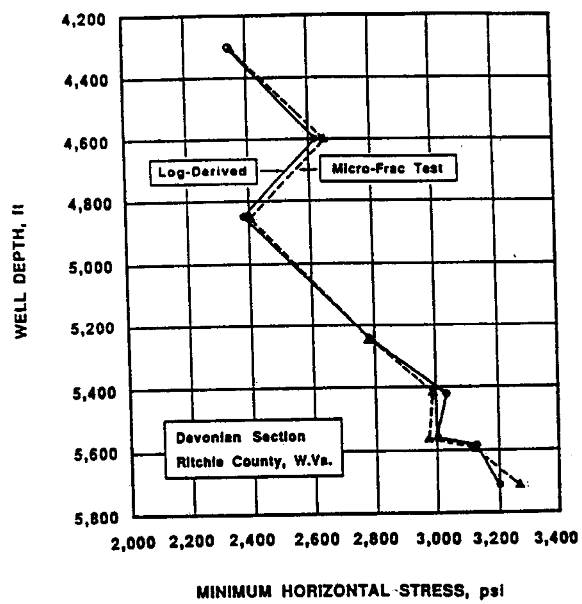


Figure 8 — Correlation between static and dynamic values

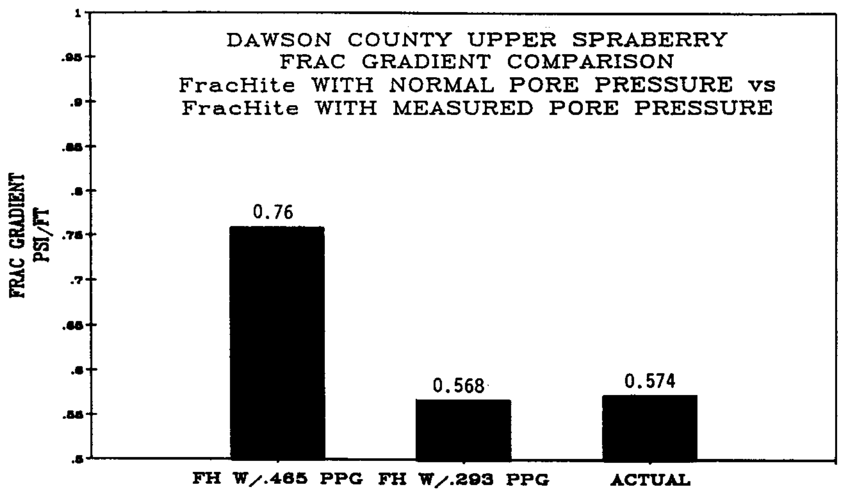


Figure 9 — FracHite fracture gradient assuming pressure gradient of 0.465 ppg was 0.76. FracHite gradient using RFT input was 0.568. Actual gradient during job was 0.574.

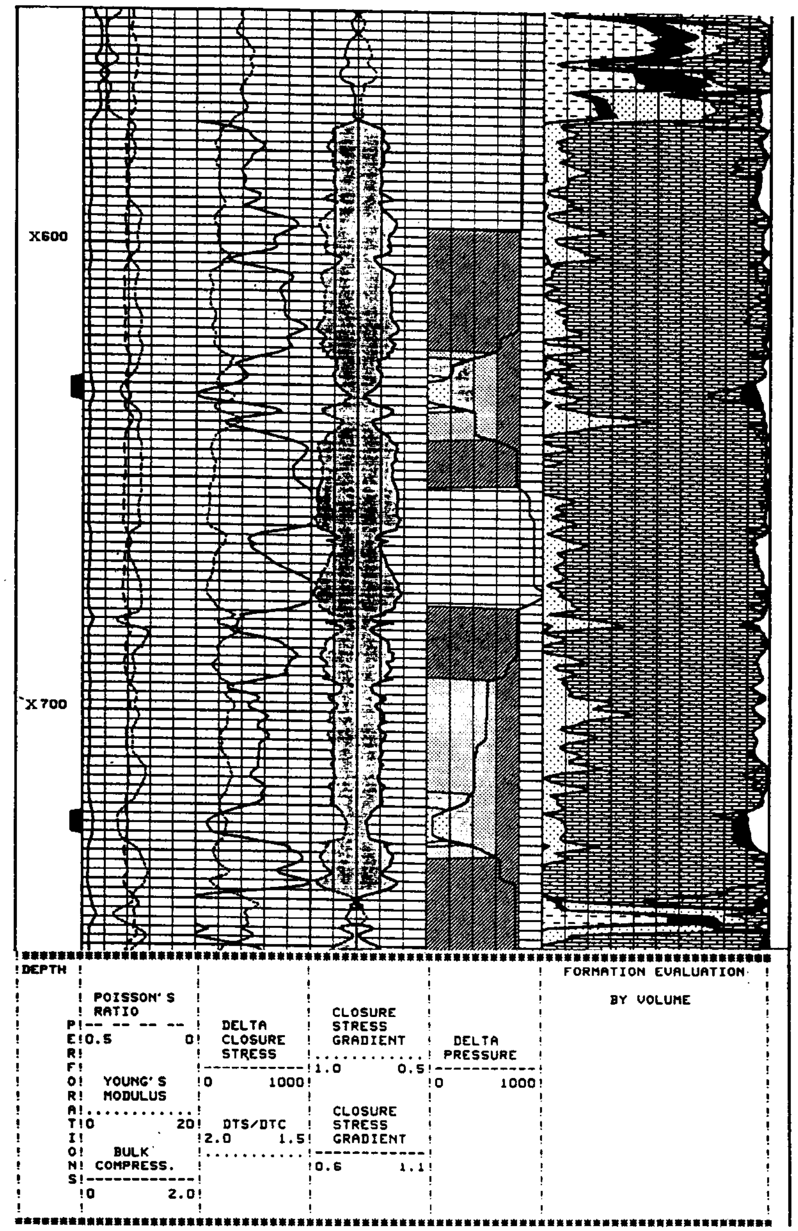


Figure 10 — FracHite example used to determine injection pressure limit of 400 psia over fracture pressure of 4750 psia

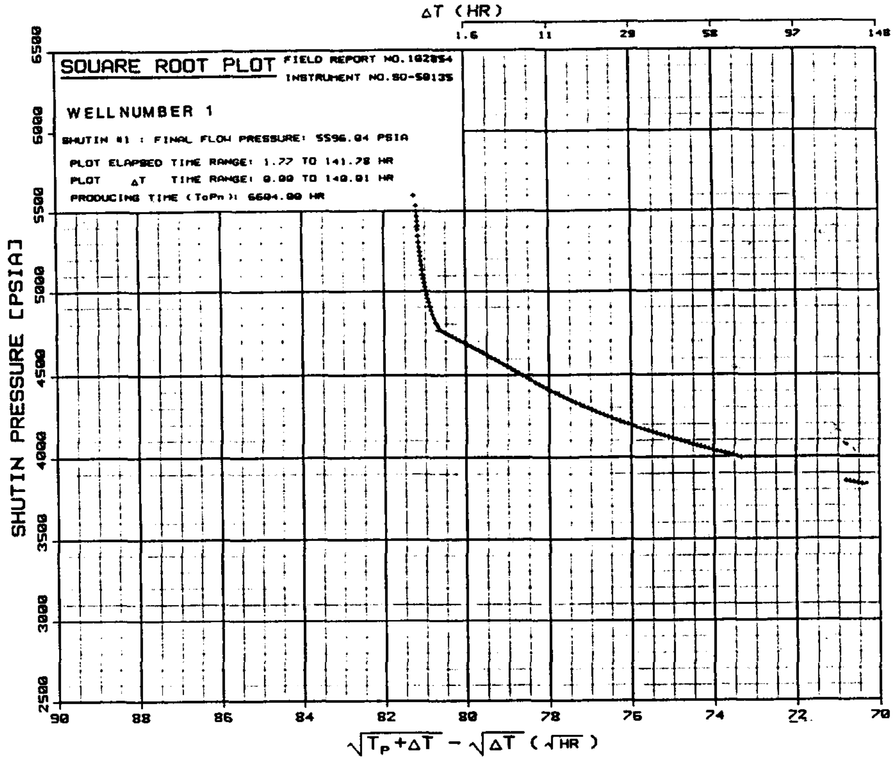


Figure 11

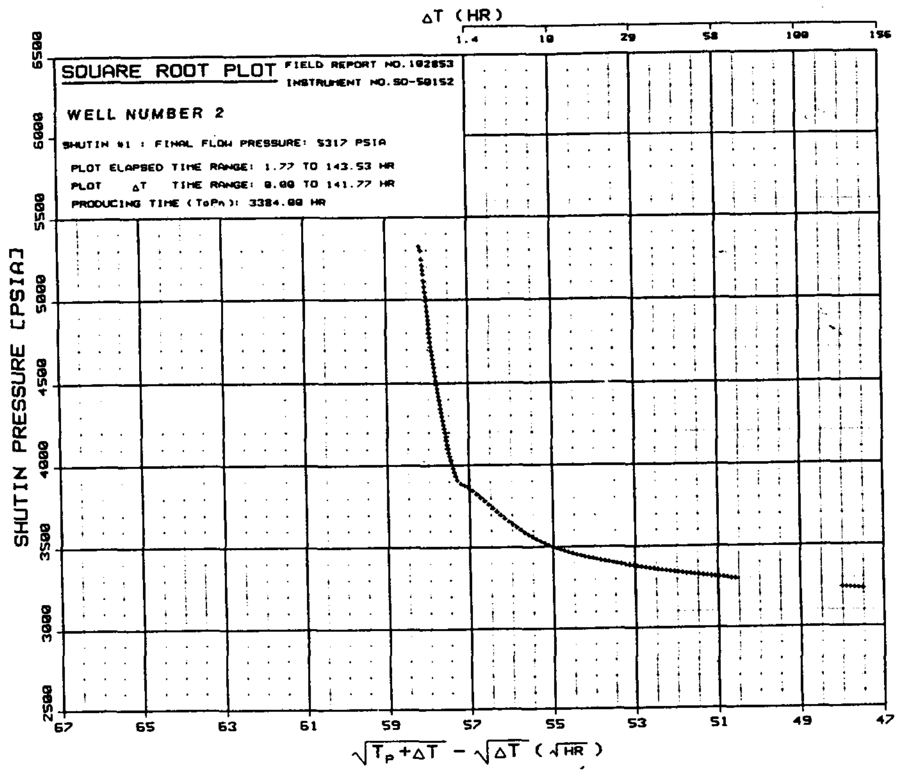


Figure 12

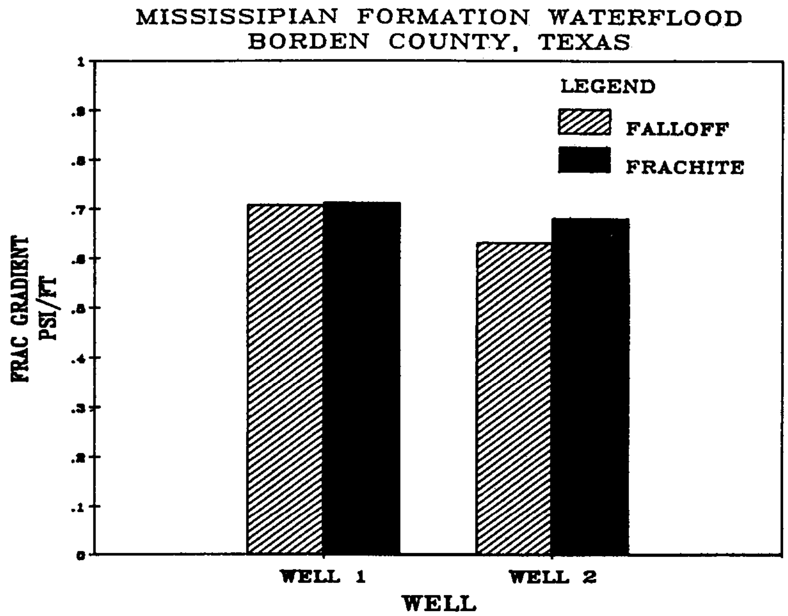


Figure 13 — Frac gradient comparison — falloff test vs FracHite