USING TRACERS TO EVALUATE PROPPED FRACTURE WIDTH

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INTRODUCTION

Many production engineers are beginning to use three-dimensional (3-D) fracture propagation models to design and analyze hydraulic fracture treatments. To use a 3-D model, one must define the layers that comprise the reservoir and develop detailed datasets that accurately describe the layers.[1,2,3] The data that are critical for designing and analyzing hydraulic fracture treatments are in-situ stress, formation permeability, formation porosity, reservoir pressure, and Young's modulus. Many times, these parameters can be determined from logs and/or correlated to lithology.

Once the datasets are obtained, one can use a three-dimensional fracture propagation model to estimate values of created or propped fracture length, width, and height. To understand and improve the fracture design process, the engineer must confirm the estimates of fracture dimensions that are predicted by a fracture propagation model. To verify the model, one must analyze field data to be sure the field data are consistent with the model results.[4] For example, the net pressure predicted by the 3-D fracture propagation model should closely match the net pressures observed in the field. When net pressure is adequately matched, we usually find that the overall created fracture dimensions predicted by a 3-D fracture propagation model are reasonable. To determine estimates of propped fracture length, one must also analyze post-fracture production and pressure transient data . Because of fracture fluid cleanup problems, we often find that values of propped fracture length generated by analyzing field production data are much shorter than the created fracture length predicted by the fracture propagation model.[5] Detailed engineering studies are often required to reconcile the differences.

To directly measure values of fracture width, one must perform a fracture treatment in openhole, then use a downhole imaging tool to "see" the fracture. Such an approach is not usually practical. In this paper, we will describe a method to qualitatively estimate the propped width profile at the borehole that uses radioactive tracers. Confirming the propped width profile generated by a model with field data can be very beneficial and informative.

We have found that the use of zero wash radioactive tracers can help us learn both (1) where the fracture fluid is going and (2) where the proppant resides in the fracture near the wellbore.[5,6] Assuming the level of radioactivity is proportional to volume, then the level of radioactivity will also be proportional to the propped fracture width. As such, one can obtain qualitative estimates of propped fracture width at the wellbore using a radioactive tracer where the strength of the radioactive signal is proportional to fracture volume near the wellbore.

The objectives of this paper are to discuss what factors control the fracture width profile and how to obtain data to compute fracture width. We also explain how one can use radioactive tracers to develop data that can be analyzed to determine qualitative estimates of propped fracture width. Finally, we provide several examples to illustrate how one can estimate values of propped fracture width, and how those values can be used to calibrate a 3-Dimensional fracture propagation model.

The information described in this paper can be used by a production engineer to obtain a better understanding of a specific hydraulic fracture treatment. As our understanding of hydraulic fracturing improves, we should be able to design the optimal fracture treatment with more certainty. When we design and pump the optimal fracture treatment, we maximize the economic return on developing oil and gas properties.

DESCRIBING LAYERED SYSTEMS

All low to medium permeability reservoirs that must be hydraulically fracture treated to stimulate productivity can be described as layered systems. To design and analyze a hydraulic fracture treatment, one must obtain profiles of lithology, porosity-thickness, permeability-thickness, and in-situ stress by layer. Figs. 1 and 2 illustrate the vertical profiles of lithology, Poisson's Ratio, Young's Modulus, permeability, and in-situ stress. These data came from the Gas Research Institute's (GRI) SFE No. 3 well in Harrison County, Texas. After one accurately derives the profiles as illustrated in Figs. 1 and 2, one can use a three-dimensional fracture propagation model to estimate the fracture width distribution. Such a distribution is illustrated in Fig. 3.

To develop accurate datasets, one should first review logs, cores, and cuttings to determine formation lithology and the stratigraphy. Using the lithologic and stratigraphic data, one can divide the formation into 10 to 20 layers, depending on the situation. The next step is to use data or correlations to compute estimates of porosity thickness, permeability-thickness, in-situ stress, Young's modulus, and Poisson's ratio for each layer.[2] To compute accurate estimates of in-situ stress, one must know the pore pressure in each layer. If the well is in a new reservoir, one can assume that the pore pressure gradient is the same in each layer. However, in older fields, one may need to run repeat formation testers or pressure buildup tests to estimate the pressure in reservoir layers that have been produced in offset wells. It may also be necessary to run a well test to confirm estimates permeability, reservoir pressure, and in-situ stress.

After the layered reservoir description is completed, the dataset can be used to generate a three-dimensional view of the hydraulic fracture. Of particular importance is the width distribution at the wellbore and the average propped fracture length. These factors, along with the permeability of the reservoir, will affect both the flow rates and ultimate recovery from the reservoir. To determine estimates of propped fracture length, one can history match both post-fracture production data and pressure transient data using a finite difference reservoir simulator or analytical solutions.[8] If one has properly described the reservoir system and the fracture fluid cleans-up properly, these post-fracture analyses provide very reasonable estimates of propped fracture length.[5]

When we analyze production and pressure transient data, we also obtain an estimate of the average fracture conductivity. However, to verify our layered reservoir description, we need to know values of propped fracture width at the wellbore for each layer of rock. Once we have verified our fracture model and our layered reservoir description, we can then design the optimal fracture treatment.

MODERN TRACER TECHNOLOGY

Using radioactive tracers to identify well stimulation fluid and proppant placement can be an effective technique for the evaluation of proppant distribution near the wellbore, fluid distribution near the wellbore, proppant settling, stage distribution, and fracture height in certain cases.

The advent of multi-spectral gamma ray tools and the software to differentiate multi-isotopes and their position with respect to inside or outside the wellbore has significantly improved the utility of tracers. These innovations allow us to identify differences in the placement and/or distribution of more than one proppant concentration or different types of proppant in the fracture near the wellbore.

The development of a technique to eliminate the loss of radioactive tracer from a proppant carrier has greatly enhanced the ability to use improved logging technology to evaluate proppant placement in fractures communicating with the wellbore. These zero-wash tracers eliminate losses due to wash-off and abrasion during pumping of proppants downhole. This effectively allows us to estimate where the proppant is located adjacent to the wellbore, as opposed to just identifying the points of entry into the fracture from the wellbore.

The tracers available for these applications include Iridium-192 (Ir-192), Scandium 46 (Sc-46), and Antimony 124 (Sb-124). These tracers are produced by incorporating salts of these isotopes within the physical matrix of a high strength ceramic solid. Both the size and density of the radioactive particles are comparable to the proppants currently used by industry.

Tracers may be used to evaluate proppant stage placement by incorporating different isotopes in the early and late proppant concentrations pumped during a treatment. This technique is useful to evaluate the position of these proppant stages at the wellbore with respect to distribution across single zone or multizone perforations. Liquid tracers may be used to verify zone entry by the fracture fluid and/or the pad fluid.

Since zero-wash tracers have virtually eliminated the cumulative buildup or washoff of radioactive isotopes within the wellbore, perforation tunnels, and fractures communicating with the wellbore, a more accurate understanding of tracer peak amplitude from multi-spectral gamma ray logs is possible. The tracer(s) evident at the wellbore is indicative of the last concentration of proppant to be placed at that point. If no washoff has occurred and no significant channels exist behind pipe, then the tracer concentrations investigated by the logging tools will be proportional to the volume of proppant in place in the hydraulic fracture within the depth of investigation range of the tools (usually 8-12 inches).

A precise amount of isotope is placed within the proppant fluid slurry. The amount of isotope will be proportional to the amount of proppant and fluid pumped; therefore, the gamma ray intensity shown on logs should be indicative of the fracture volume or fracture width. Considering that the formation, cement, and tubular goods attenuate the gamma ray signals, the amplitude of those signals tends to be proportional to the size of the aperture or fracture width near the wellbore. Similar investigations by Reis found that gamma ray intensity decayed exponentially with radioactive tracer distance into the formation, and the attenuation of gamma rays reaching a detector is independent of wellbore diameter. Thus, Reis developed an equation to determine the effective in-situ aperture (width) intersecting a wellbore using data from radioactive tracers.[8]

COMBINING THE TWO TECHNOLOGIES

In this paper we describe 1) the development of datasets and the use of three-dimensional fracture propagation models to design a fracture treatment, and 2) how modern tracer technology can be used to determine the position of fluids and proppants in a fracture near the wellbore. We now explain how these two technologies can be coupled to improve our understanding of hydraulic fracturing and to verify our methodology in determining datasets and modeling hydraulic fractures.

Figs 1, 2, and 3 illustrate a typical layered reservoir and created fracture width profile generated using a three-dimensional model. The fracture width created during a fracture treatment will be controlled by both the net pressure in the fracture and the mechanical properties of the rock layers. The fluid flowing down the fracture can move more easily in the wider parts of the fracture; thus, most of the fluid and proppant will tend to be contained in the layers where the fracture width is maximum. The new tracer material, when properly added to the fracturing fluid, will be proportional to the volume of fracture fluid and/or the volume of fracture proppant. As such, when one runs a post-fracture radioactive survey, the strength of the radioactive signal should be proportional to fracture volume, which should be proportional to fracture width at the wellbore. With those assumptions, one can use a three-dimensional fracture propagation model to history match the data collected during and after the hydraulic fracture treatment to determine if the model prediction is compatible with the tracer data.

During the history matching process, we must model the correct injection volume, the correct injection rate, and closely match the injection pressures during the treatment. One must carefully compute net pressures by obtaining accurate estimates of in-situ stress and correcting for near wellbore pressure drops.[4] These near wellbore pressure drops can be caused by perforations and/or fracture tortuosity.[10] After the production engineer successfully matches the fracture data, one can then compare the propped fracture width profile obtained from the fracture model with the profile obtained using the tracer survey. These profiles can be compared qualitatively to determine if they agree. If they do not agree, the engineer should consider changing the description of the layered reservoir and reanalyzing the fracture treatment data until a reasonable match is obtained between the computed width profile and the profile estimated using radioactive materials. We illustrate this concept in the following field examples.

FIELD EXAMPLES

Example No. 1

Example No. 1 is a middle bench Frontier zone in Wyoming that was fracture treated with 100,000 gallons of 70 quality nitrogen foam and 235,000 lbs of 20/40 sand. The job was pumped down casing at 40 BPM at 4800 psig surface treating pressure with an instantaneous shut-in pressure of 3200 psig. With an initial production rate of about 3 MMcf/d, the well has stabilized at over 1.0 MMcf/d after three months. In Fig. 4, the after-frac spectral gamma ray log indicates that the upper and lower sets of perforations do not have proppant in communication with the wellbore. The interval from 5,780 ft - 5,800 ft was adequately covered with both pad and proppant. The interval from 5,664 ft - 5,702 ft had both pad and proppant adjacent to the wellbore, as well as additional downward growth to 5,733 ft. Scandium 46 (Sc-46) was used in a water soluble liquid form to trace the 15,000 gallon foam pad, and Iridium 192 (Ir-192) was used to trace the 20/40 sand. Highest proppant tracer peak amplitude (Ir-192) was noted across two lower stress pay intervals and little or no proppant was noted across perforations above 5,200.

We have compiled data describing the reservoir and the fracture treatment for Example 1. The data in Table 1 are basic well information. Table 2 presents the layer data for this well.

Using these data, a 3-Dimensional fracture propagation model was used to estimate both the created and propped fracture width profile at the wellbore. These profiles are shown in Fig.5.

The created fracture height at the wellbore was computed to be over 350 ft. However the propped fracture height according to the 3-D model is only about 100 ft in the upper zone and 20 ft in the lower zone, as illustrated in Fig. 5. These values correlate well with the tracer data illustrated in Fig. 4.

Example No. 2

For Example No. 2, a Lewis sandstone interval was fracture treated with 125,000 gallons of CO_2/N_2 binary foam carrying 250,000 lbs of 20/40 ISP at 20 BPM down 2 7/8" tubing at 6000 psi surface treating pressure. The pad volume was traced with Sc-46, while the proppant was Ir-192.

The well had an initial gas production rate of 5.1 MMcf/d and is currently flowing 3 MMcf/d. Fig. 6 illustrates the radioactive tracer data for Example No. 2. The perforated intervals all have proppant across the perforations, with the higher proppant concentration distributed from 8,350 ft to 8,452 ft. Maximum tracer peak amplitude is adjacent to perforations in the upper interval (8,343' - 8,400'). The maximum tracer peak amplitude is near the lower interval (8,422'-8,430'), with only some slight downward distribution below the perforations.

Tables 3 and 4 present data that illustrate the well and layer properties for the Lewis sandstone reservoir.

We have used the data in Fig. 6, Table 3 and Table 4 to run a 3-Dimensional fracture propagation model. The estimates of created and propped fracture width at the wellbore for Example No. 2 are illustrated in Fig. 7. The created and propped fracture heights at the wellbore is computed to be about 200 ft and 150 ft, respectively. From Fig. 6, the tracer shows that radioactive proppant is evident for about 110 ft.

Example No. 3

The Tubb formation is a thick dolomite in West Texas. Example Well No. 3 was fracture stimulated with 65,000 gallons of 35 lb/1000 gal delayed crosslinked borate gel. The treatment carried 121,000 lbs of 20/40 sand and 17,000 lbs of 20/40 resin coated sand (RCS). The 121,000 lbs of sand was traced with Sc-46 isotope and the 17,000 lbs of resin coated sand was traced with Ir-192 isotope. The treatment was pumped at 45 BPM at 4500 psig down 5 1/2 inch casing. This well was drilled, broken-down with acid, then fracture treated. The well made 90 BOPD and 540 MCFPD after the treatment and is making 40 BOPD and 280 MCFPD after 7 months.

The tracer data in Fig. 8 indicate that most of the total resin coated sand (6 ppg) volume was placed between 4,320 ft and 4,376 ft adjacent to the lower stress contrast. The sand (1-5 ppg stages) cover more of the pay zone.

Detailed information for Example Well No. 3 are included in Fig. 8 and Tables 5 and 6. These data were used to run a 3-D fracture propagation model. The results of that analysis are presented in Fig. 9. The created and propped fracture heights for Example No. 3 were computed to be about 400 ft and 200 ft, respectively. In Fig. 8, the radioactive tracer data show a propped height near the wellbore is about 90 ft. The strength of the tracer signal also correlates qualitatively with the values of fracture width.

CONCLUSIONS

Based on the data in this paper, we offer the following conclusions.

1. The height and width profile of a hydraulic fracture in a layered reservoir can be characterized with a 3-Dimensional hydraulic fracture propagation model, if adequate input data are available.

2. Modern radioactive tracer technology can be used to estimate the location of various fluids and proppants that are near the wellbore. If zero-wash tracers are used, the strength of the tracer signal should be roughly proportional to fracture volume.

3. In three field case histories we have reviewed, the created fracture height at the wellbore was always much larger than the propped fracture height.

4. For the three case histories, the values of created fracture height at the wellbore, as predicted from the 3-D fracture propagation model, compared favorably with the values one can estimate from the tracer log.

5. The comparison of tracer log data with the values of propped fracture width estimated by the model,

indicates that there is qualitatively agreement between the two methods for the 3 field case histories we have reviewed.

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Table 1
Well Data for Example 1

Location	Wyoming
Formation	Frontier
Reservoir Pressure	3300 psi
Reservoir Temperature	135°F
Average Permeability	0.1 md
Average Porosity	10%
Reservoir Fluid	Gas
Fracture Fluid Type	70% N_2 Foam
Fracture Fluid Volume	100,000 gal
Proppant Volume	235,000 lbs 20/40 Sand
Average Injection Rate	40 BPM
Average Injection Pressure	4800 psi
Minimum In-situ Stress	4400 psi

Table 2
Layer Data for Example 1

Layer	Lithology	Depth Interval (ft)	In-situ Stress (psi)	Young's Modulus (psi)
1	Shale	5,200-5,577	6,000	2.75×10^6
2	Shaly Sand	5,577-5,606	5,200	2.00×10^6
3	Shale	5,606-5,626	5,600	2.75×10^6
4	Siltstone	5,626-5,650	5,550	2.25×10^6
5	Shale	5,650-5,662	5,500	2.75×10^6
6	Sand	5,662-5,703	4,400	2.50×10^6
7	Shaly Sand	5,703-5,714	5,000	2.00×10^6
8	Siltstone	5,714-5,732	5,600	2.25×10^6
9	Shale	5,732-5,750	6,000	2.75×10^6
10	Limey Shale	5,750-5,760	6,200	3.00×10^6
11	Limey Shale	5,760-5,776	5,800	3.00×10^6
12	Shaly Sand	5,776-5,796	4,800	2.00×10^6
13	Shaly Sand	5,796-5,804	5,400	2.00×10^6
14	Shale	5,804-5,834	5,600	2.75×10^6
15	Shaley Sand	5,834-5,864	5,200	2.00×10^6
16	Shale	5,864-6,000	6,000	2.75×10^6

Table 3
Well Data for Example 2

Location	Wyoming
Formation	Lewis
Reservoir Pressure	4500 psi
Reservoir Temperature	170°F
Average Permeability	0.05 md
Average Porosity	10%
Reservoir Fluid	Gas
Fracture Fluid Type	CO_2/N_2 Binary Foam
Fracture Fluid Volume	125,000 gal
Proppant Volume	250,000 lbs 20/40 ISP
Average Injection Rate	20 BPM
Average Injection Pressure	6000 psi
Minimum In-situ Stress	6700 psi

Table 4
Layer Data for Example 2

Layer	Lithology	Depth Interval (ft)	In-situ Stress (psi)	Young's Modulus (psi)
1	Shale	8,000-8,308	7,900	2.75×10^6
2	Limey Sand	8,308-8,316	7,650	3.00×10^6
3	Sand	8,316-8,332	7,200	2.50×10^6
4	Limey Shale	8,332-8,342	7,000	3.00×10^6
5	Sand	8,342-8,398	6,700	2.50×10^6
6	Limey Shale	8,398-8,417	7,200	3.00×10^6
7	Sand	8,417-8,432	6,600	2.50×10^6
8	Limey Shale	8,432-8,450	7,400	3.00×10^6
9	Limey Shale	8,450-8,482	7,600	3.00×10^6
10	Limey Shale	8,482-8,600	7,700	3.00×10^6

Table 5
Well Data for Example 3

Location	West Texas
Formation	Tubb
Reservoir Pressure	900 psi
Reservoir Temperature	100°F
Average Permeability	8.2 md
Average Porosity	10%
Reservoir Fluid	32°API Oil
Fracture Fluid Type	35 lb/1000 gal x-Link Borate
Fracture Fluid Volume	65,000 gal
Proppant Volume	121,000 lbs 20/40 Sand 17,000 lbs 20/40 RCS
Average Injection Rate	45 BPM
Average Injection Pressure	4500 psi
Minimum In-situ Stress	2400 psi

Table 6
Layer Data for Example 3

Layer	Lithology	Depth Interval (ft)	In-situ Stress (psi)	Young's Modulus (psi)
1	Shale	4,000-4,200	3,500	$9x10^6$
2	Shaly Dolomite	4,200-4,280	3,000	$9x10^6$
3	Shaly Dolomite	4,280-4,328	2,530	$9x10^6$
4	Porous Dolomite	4,328-4,334	2,500	$5x10^6$
5	Porous Dolomite	4,334-4,342	2,400	$5x10^6$
6	Porous Dolomite	4,342-4,350	2,580	$5x10^6$
7	Porous Dolomite	4,350-4,364	2,530	$5x10^6$
8	Porous Dolomite	4,363-4,375	2,680	$5x10^6$
9	Tite Dolomite	4,375-4,380	2,530	$8x10^6$
10	Porous Dolomite	4,380-4,394	2,640	$5x10^6$
11	Tite Dolomite	4,394-4,404	2,750	$8x10^6$
12	Tite Dolomite	4,404-4,426	2,900	$8x10^6$
13	Porous Dolomite	4,426-4,433	2,600	$5x10^6$
14	Porous Dolomite	4,433-4,443	2,650	$5x10^6$
15	Porous Dolomite	4,443-4,456	2,550	$5x10^6$
16	Tite Dolomite	4,456-4,500	3,000	$8x10^6$
17	Shale	4,500-4,700	3,500	$8x10^6$

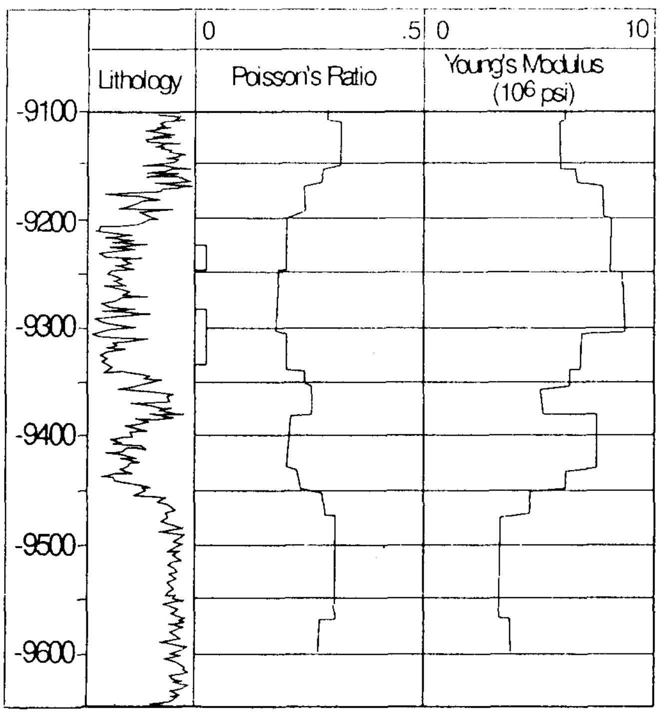

Figure 1 - Distribution of Young's modulus and Poisson's ratio for the Cotton Valley Taylor section in SFE No. 3

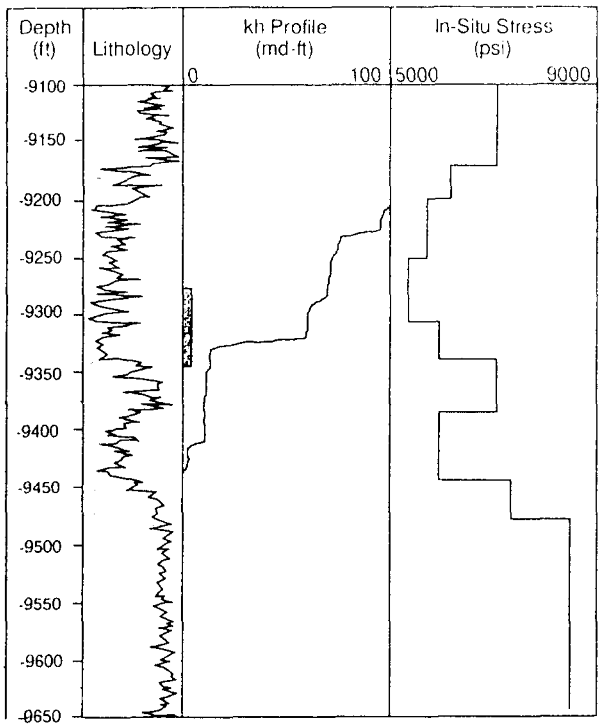

Figure 2 - Distribution of in-situ stress for the Cotton Valley Taylor section in SFE No. 3.

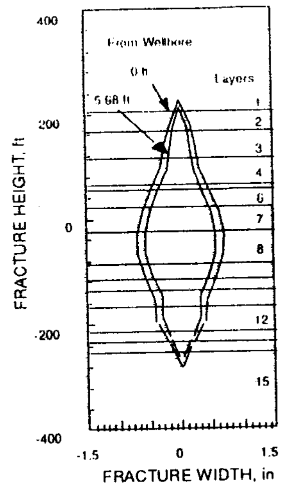

Figure 3 - Fracture width profile for SFE No. 3.

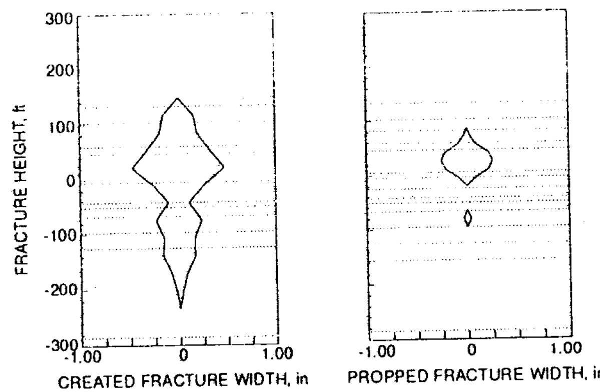

Figure 5 - Created and propped width profiles for Example 1.

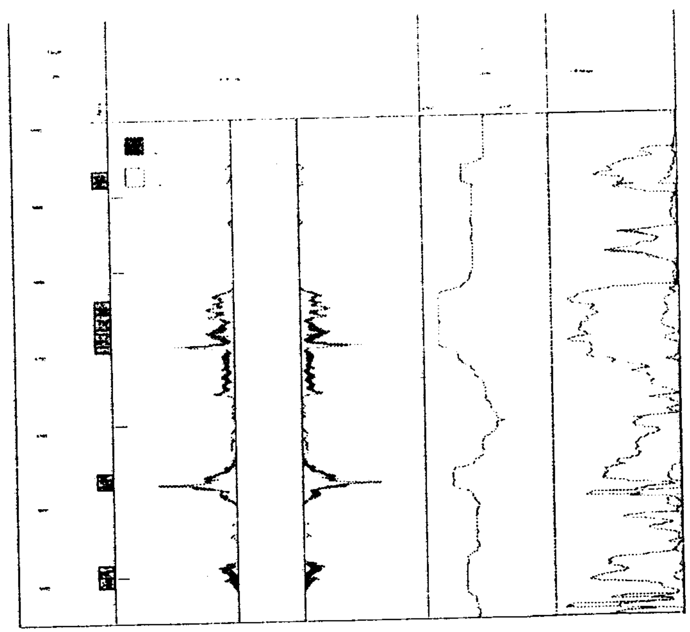

Figure 4 - Tracer log and in-situ stress profile for Example 1.

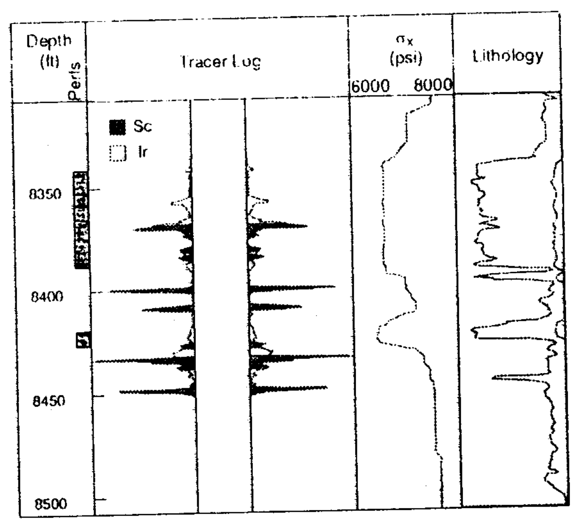

Figure 6 - Tracer log and in-situ stress profile for Example 2.

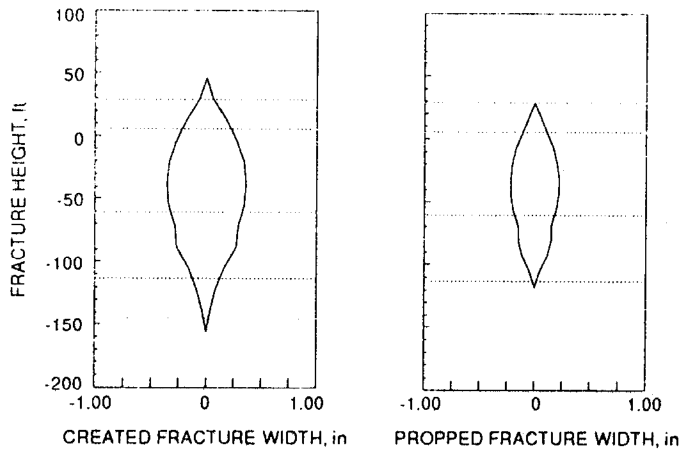

Figure 7 - Created and propped width profiles for Example 2.

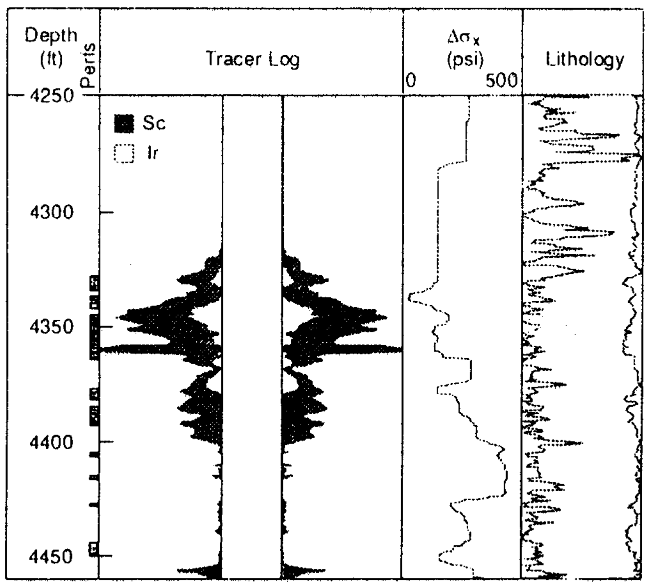

Figure 8 - Tracer log and in-situ stress profile for Example 3.

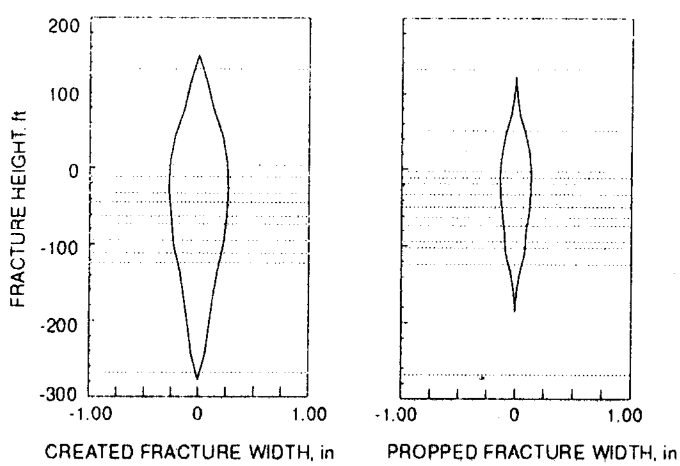

Figure 9 - Created and propped width profiles for Example 3.