ESTIMATION OF INSITU FORMATION STRESS PROFILES FROM ANALYSIS OF HYDRAULIC FRACTURING TREATMENT DATA

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ABSTRACT

This paper describes a process used to analyze hydraulic fracturing treatment data which leads to the implicit estimation of formation stress profiles. The field example is given for the San Andres formation, where a fracture stimulation was analyzed by history matching the treatment data and a resultant stress profile determined. The stress profile determined was then applied to other surrounding wells which were stimulated, and a consistent match of the treatment data resulted. This procedure leads to a better estimation of created fracture geometry by matching actual treatment data and provides a basis for design and optimization of future treatments.

The method of identifying the distance between major stress variations and the magnitude of the difference in this stress will be discussed. The process involves using a 3-D fracture simulator with multi-layering capability, allowing the distance to stress differences to be identified.

INTRODUCTION

Insitu stress profiles are known to play a dominant role in the fracture geometry that develops from a hydraulic fracture stimulation treatment.[1-3] The determination of an insitu stress profile (stress within the pay zone as well as surrounding zones) is critical to properly design an optimized fracture treatment. The insitu stress profile, as well as rock properties such as Young's Modulus, will control the height, width, and length created by the fracture treatment. There are many methods available to determine or estimate this stress profile such as; core analysis, injection/falloff tests, and acoustic logging.[4-6] Each of these methods requires additional costs. The method described here provides an estimation of the stress profile as a result of analyzing the surface treatment pressure data. No additional logs must be run, core analysis done, or stress tests performed. Although this method does not a provide a detailed profile that is correlated with depth, it does provide a profile that can be used as a basis for design and optimization of future treatments.

This method of analysis was developed due to the absence of stress data in many West Texas completions. Previous analysis and designs were based on 2-D models which assume a fixed height.[7-9] This method incorporates the use of a 3-D fracture simulator to history match the actual treatment pressure. In order to determine a match an estimated stress profile must be used. The profile is then refined until an adequate match of the treatment pressure results. The resulting profile can then be used to design future treatments in the same area. As more treatments and more analyses are performed in a specific area, an enhanced estimation of the stress profile can result. Case examples of this process are presented for three wells fracture treated in the San Andres formation.

MODEL BACKGROUND

This model was developed through the Gas Research Institute (GRI) research efforts.[10-12] The model is able to read real-data in real-time and allows analysis on-site during the treatment.[13-18] It is a lumped-parameter 3-D hydraulic fracture simulator. The model was initially tested and developed through Staged Field Experiment (SFE) wells. In these wells many detailed tests (core analysis, acoustic logs, stress testing, etc.) were performed to identify the insitu stress profile, as well as other reservoir properties. Since this time the model has been used many times to analyze, design, and predict production for hydraulic fracture treatments. Our use of the model as a method to estimate insitu stress profiles was developed due to the lack of stress data on many of our fracture treatments.

STRESS PROFILE DETERMINATION

Figure 1 shows the typical fracture treatment data that is used in the analysis process. This data can be analyzed either after the treatment or in real-time. Figure 2 indicates the areas of the surface pressure plot that should be history matched. The method of history matching analysis has been described in detail in reference 19. Basically the method is to iterate on several reservoir parameters (zone stress, bounding stress, Young's Modulus, Leakoff, etc.) to obtain a match of surface treating pressure. Several known data such as reservoir pressure, shut-in pressure at the end of treatment are used to enhance the analysis. In the case where a shut-in is taken during the treatment, then this pressure magnitude is also matched. Also if a minifrac treatment is performed prior to the main treatment, it provides valuable data which can be used to developed a stress profile.[20]

Figure 3 is an example of the typical data that can be derived from a minifrac treatment. In particular it provides an estimate of the closure stress (pressure) of the treatment interval and an estimate of the net pressure that is generated for the volume pumped at a specific rate. These two pieces of data provide a basis from which the main fracture analysis can be initiated. In the case where a minifrac is not performed then shut-ins (during the pad stage or the proppant stage) can provide a basis for the initiation of analysis. In order to illustrate the process of stress profile determination we will use an actual case example.

The treatment for Well #1 is shown on Figure 4. This well is located in West Texas and was completed in the San Andres formation. The fracture treated was pumped down tubing with 187,000 lbs of proppant, 1621 bbls of fluid, at 30 BPM. A shut-in was taken approximately 9 minutes into the treatment. The shut-in lasted for approximately 7 minutes. Initially, a uniform stress profile is assumed and the shut-in as mentioned earlier provides a starting point for the determination of closure pressure in the treatment zone and the net pressure generated. It was observed that a 2100 psi closure stress in the zone, with Young's Modulus of 9×10^6, would provide a match during the early portion of the treatment. An initial estimate of this pressure was made using the following simplified equation:

$$FG = (\nu/1-\nu)(P_{overburden}-P_{pore}) + P_{pore} \ldots\ldots (1)$$

Where FG = Fracture Gradient, psi/ft
$P_{overburden}$ = Overburden Pressure gradient, psi/ft
P_{pore} = Pore (reservoir) pressure gradient, psi/ft
ν = Poison's ratio

The "model pressure" in Figure 4 shows the calculated treating pressure using a uniform stress profile at 2100 psi. As can be seen, the match is good during the early shut-in but deviates from the actual tubing treatment pressure as the job progresses. Also the calculated shut-in pressure does not match the observed tubing pressure at the end of the treatment. Thus, it appears that a uniform stress profile does not provide an adequate match for the later portion of the curve and some amount of containment is required. Figure 5 shows the predicted fracture geometry if a uniform stress profile were used.

The use of 2100 psi as a closure stress corresponds to a frac gradient of 0.46 psi/ft. This is considerably lower than previously published data as well as lower than a virgin pressure interval. This well has been on production for over 10 years, and as a result the near well pore pressure has been reduced, effectively reducing the frac gradient. Data from previous treatments in this interval as well as published data have indicated frac gradients of 0.9 - 1.0 psi/ft for the San Andres formation. Thus, a bounding stress of approximately 4100 psi was used above and below the zone of interest (delta stress pressure of 2000 psi between treatment zone and bounding zones). Because of the uncertainty of this value it was not adjusted for depth and was used for both the upper and lower boundary. To recap, we have determined that the stress in the zone is 2100 psi and the stress in the surrounding zones is 4100 psi.

Now the task becomes identifying at what point the bounding stress begin to influence the fracture treatment. Figure 6 shows the pressure match for the uniform stress case up to the treatment until the shut-in at 9 minutes. It is at this point that we deduce the bounding stress has not greatly effected the treatment yet. Also, it appears from Figure 4 that the pressure match begins to deviate a few minutes after the job resumes (20 minutes). Figure 7 shows the fracture height that is created after 9 minutes. Approximately 200 feet of height has been created at this time. Thus we chose to initiate the location of the 4100 psi stress boundaries at 100 feet above mid-perf and 100 feet below mid-perf. Using this stress profile the resulting pressure history match is shown in Figure 8. As can be seen a better match is achieved. Refining the boundary location to 90 feet above and below mid-perf (180 feet of total height) results in the match shown on Figure 9. This final stress profile and the resulting fracture geometry are shown in Figure 10.

It should be noted that the shut-in pressure at the end of the treatment (Figure 9) is not exactly matched. This may result from the intersection of higher reservoir pressure (ie. stress) as the fracture propagates into the drainage area and encounters less reservoir depletion. We offer this as one possible explanation, as we have seen this in other treatments performed in previously produced intervals.

Figure 11 is a plot of the model derived net pressure and the observed (calculated from actual treating pressure not from dead string) net pressure using the bounded reservoir description. Again a good match is obtained. It is uncertain from the GR and CNC logs were the boundaries are located (Figure 12). While the measured depths to the boundaries are uncertain, the distance between them was determined.

APPLICATION TO TREATMENTS

Well #2 is located in the same field as Well #1. Using the stress profile developed for Well #1, a treatment for Well #2 was designed. An excellent surface treating pressure match was obtained for both the minifrac and main fracture treatment with only a slight modification in the thickness of the interval, shown in figures 13 and 14, respectively. The interval was enlarged from 180 feet to 230 feet. Figure 15 shows the created fracture geometry using the slightly modified stress profile determined from Well #1.

Well #3 is located in the same field as Well #1, but in a portion of the field which has a lower reservoir pressure. Again the stress profile determined Well #1 was used to design a treatment for Well #3. Figure 16 shows the surface treating pressure for the treatment and the model predicted pressure. There is a considerable discrepancy between the two curves, especially during the initial shut-in at 5 minutes. A similar analysis process to that described earlier was performed. As a result of this analysis it was determined that a lower closure pressure (stress) existed in the pay interval. The determined closure stress was 1100 psi in the pay interval. Thus using the stress profile determined for Well #1, and lowering the stress in the interval from 2100 psi to 1100 psi an excellent match of the treating pressure was obtained, as shown in Figure 17. The lower stress in the interval is due to the lower reservoir pressure in this well. Figure 18 shows the resulting fracture geometry using the modified stress profile from Well #1.

As a result of these treatments we now use a stress profile that consists of a 200 feet interval with a stress of 2100 psi and surrounding stress of 4100 psi for design of fracture treatments in this area of the San Andres. This has proven to be successful in other treatments performed in this area.

CONCLUSIONS

1. A 3-D fracture simulator can be used to provide estimations of insitu stress profiles for a specific area which can leads to design modifications for future wells.

2. Identification of insitu stress profile leads to the estimation of created fracture geometry.

3. Design and modifications based on the derived stress profile can be used to optimize fracture treatments.

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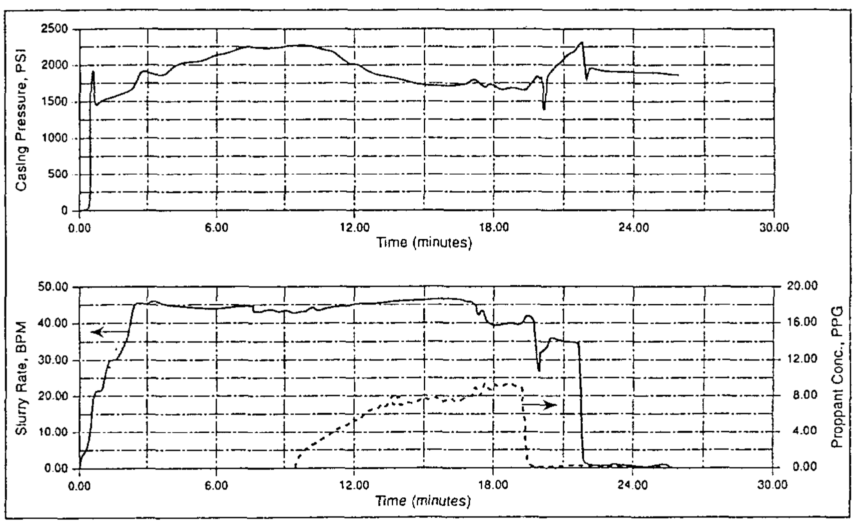


Figure 1 - Typical stimulation treatment data

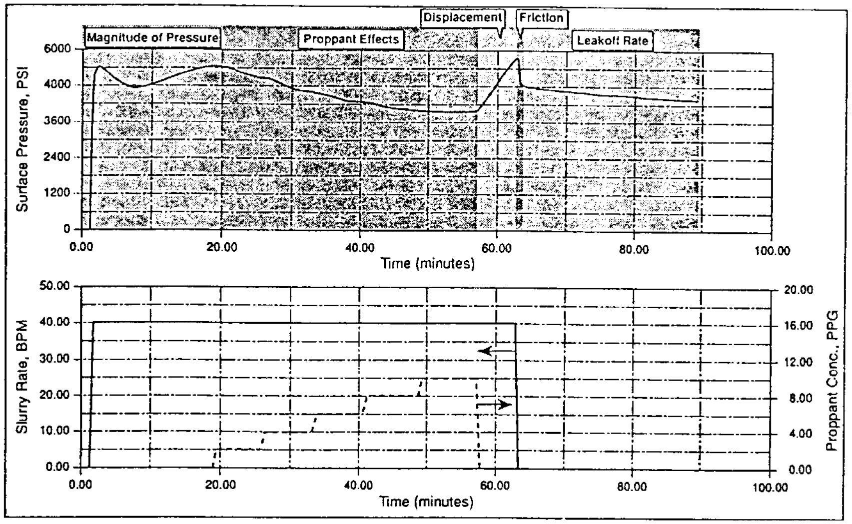


Figure 2 - Areas of pressure plot to be matched

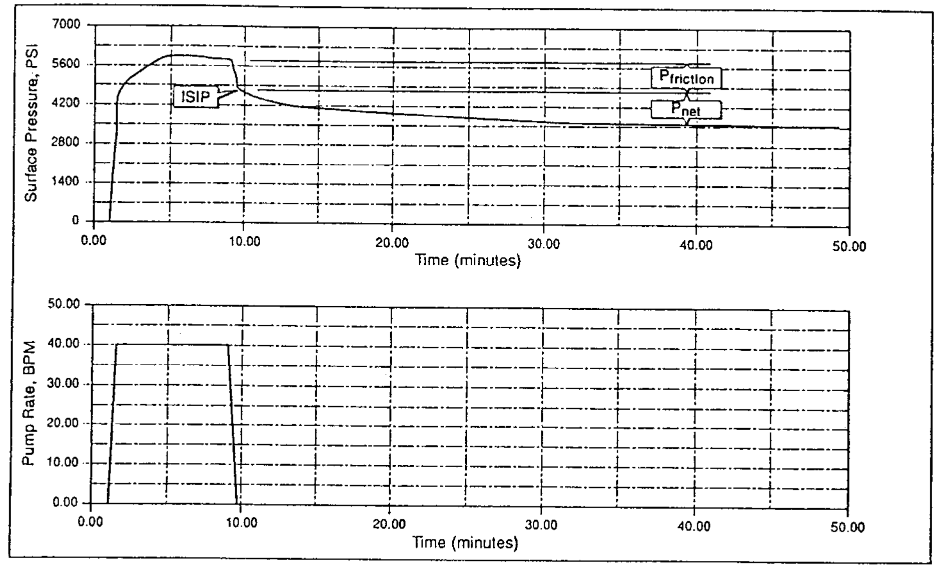
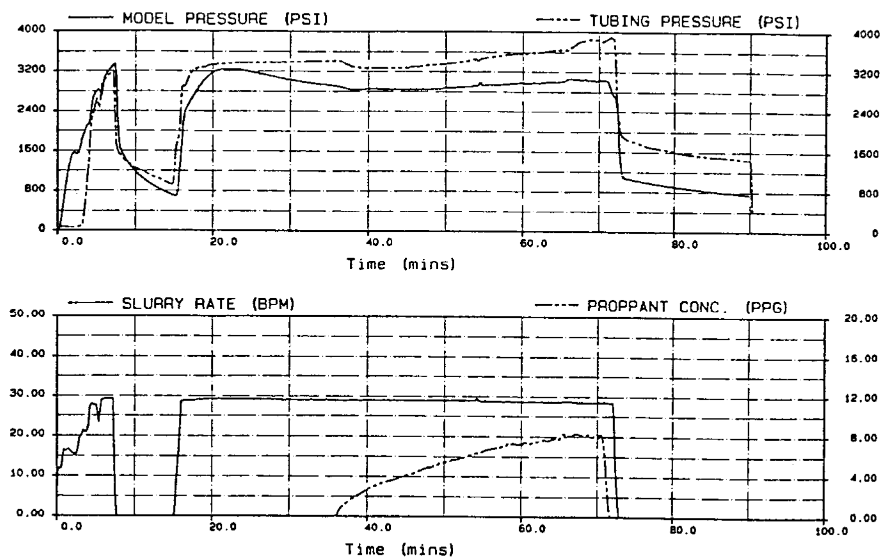


Figure 3 - Typical minifrac treatment data



pres Figure 4 - Well No.1 pressure match
using uniform stress profile

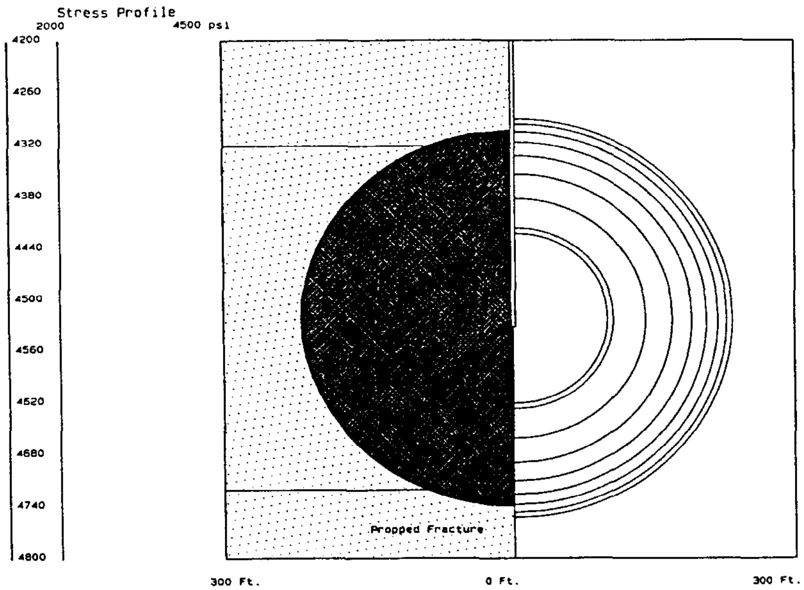


Figure 5 - Well No. 1 frac geometry using uniform stress profile

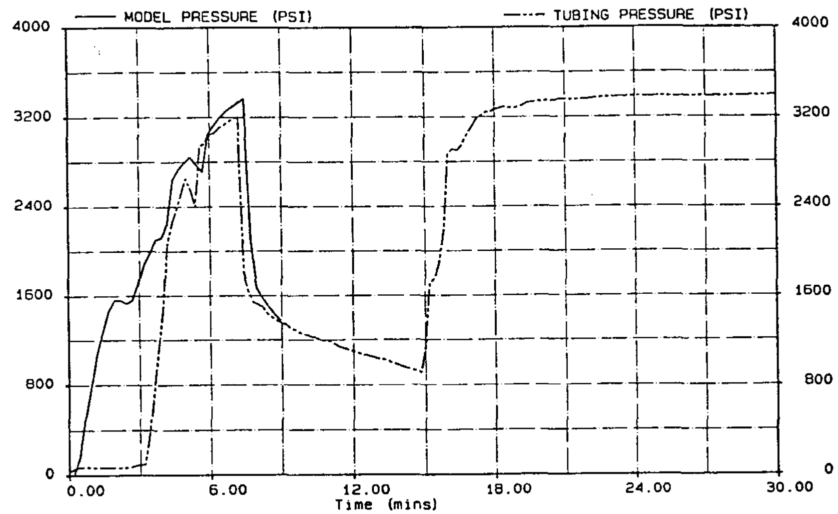


Figure 6 - Well No. 1 initial determination of stress boundary location

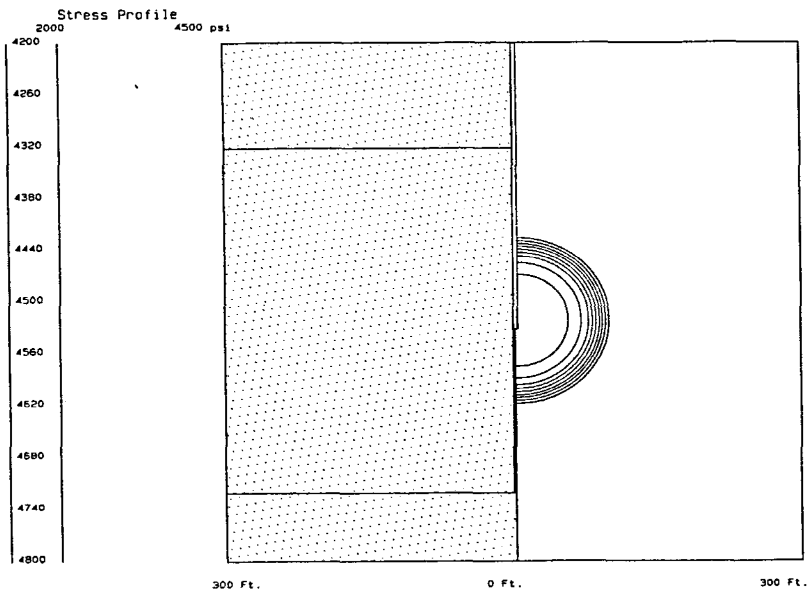


Figure 7 - Well No. 1 frac geometry at 9 minutes

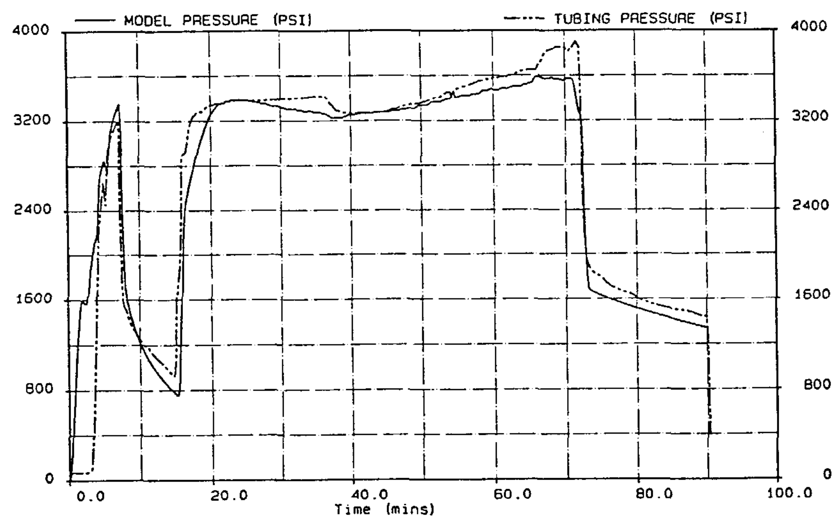


Figure 8 - Well No. 1 initial match with stress boundaries

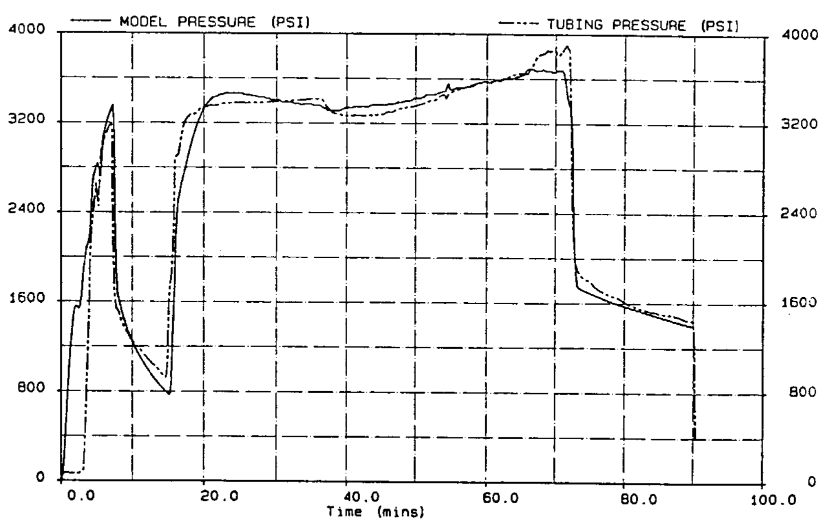


Figure 9 - Well No. 1 final pressure match with determined stress profile

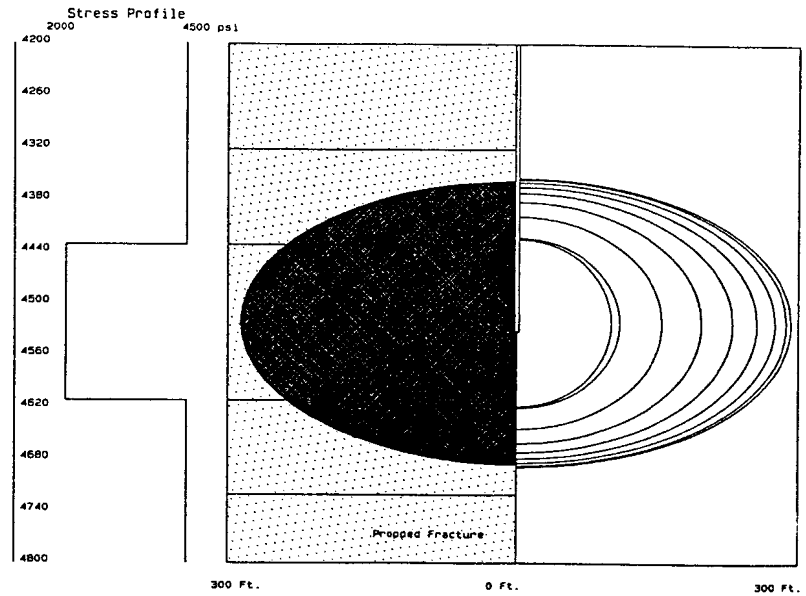


Figure 10 - Well No. 1 frac geometry with determined stress profile

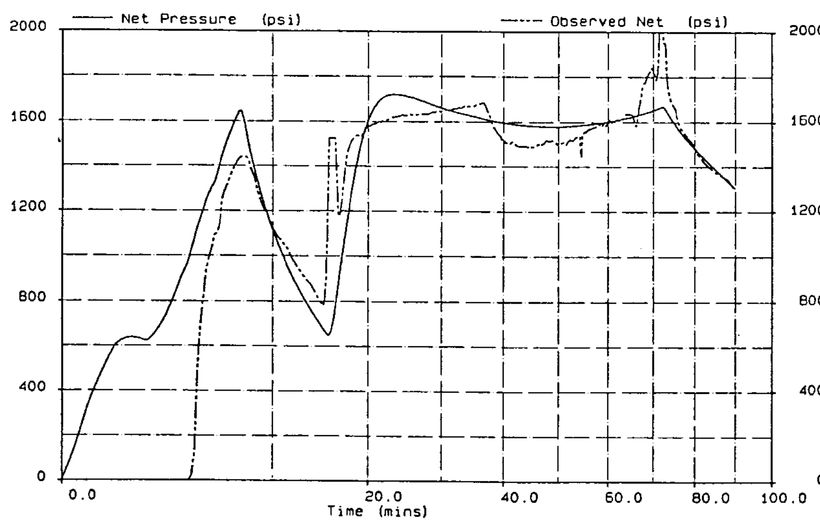


Figure 11 - Well No. 1 net pressure match

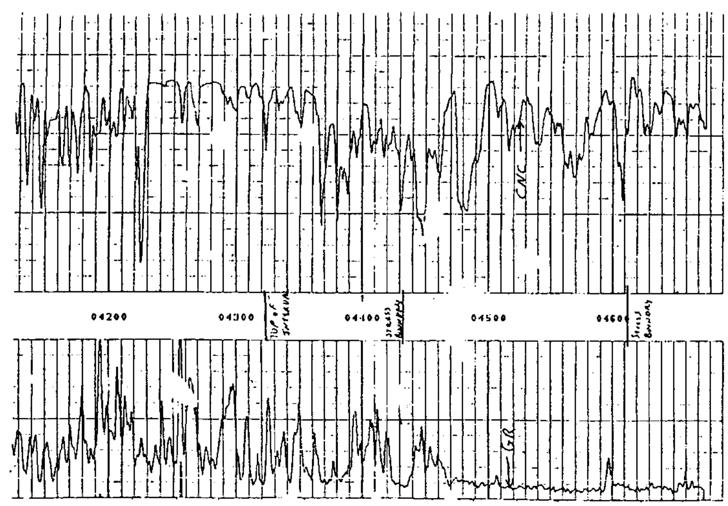


Figure 12 - Well No. 1 log

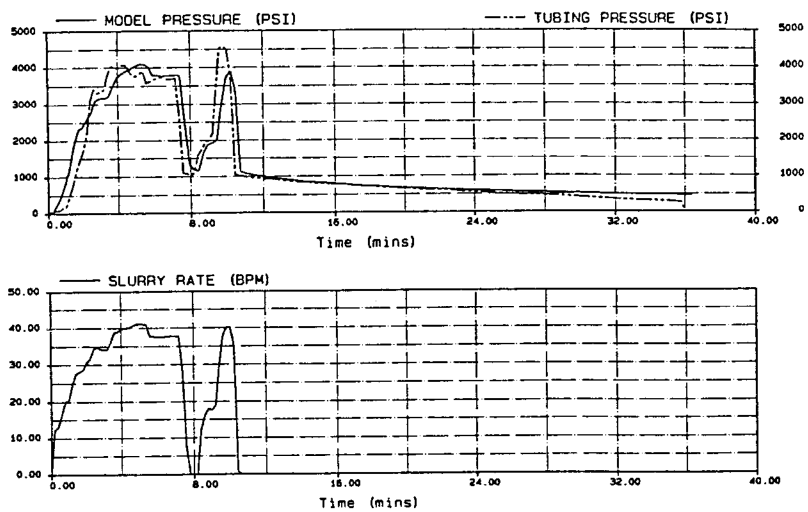


Figure 13 - Well No. 2 mini frac pressure match

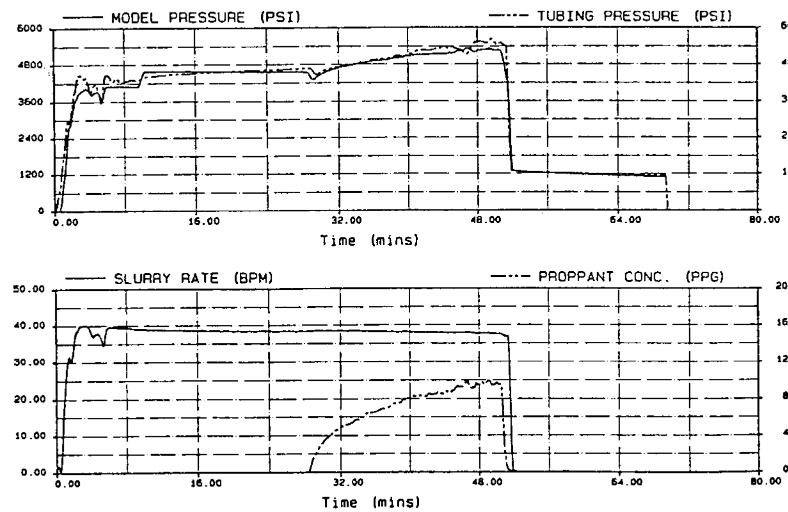


Figure 14 - Well No. 2 main frac pressure match using stress profile similar to Well No. 1

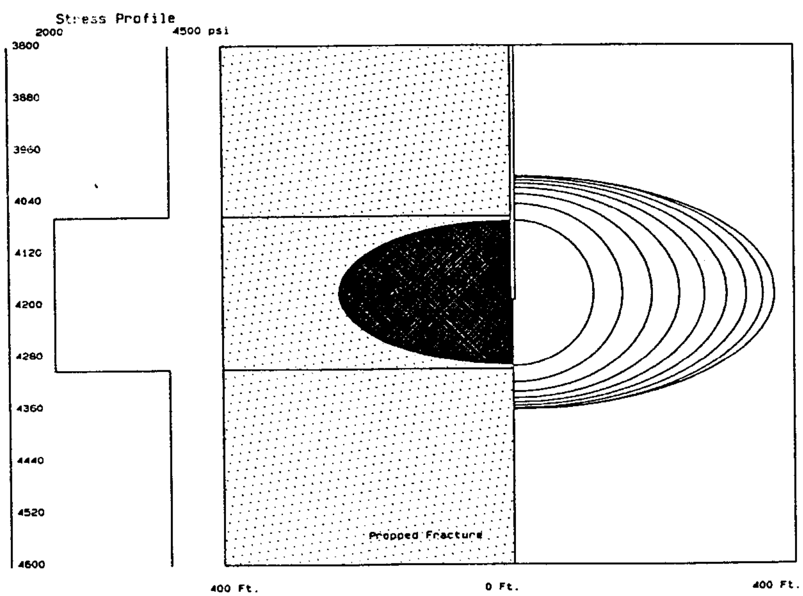


Figure 15 - Well No. 2 frac geometry using stress profile similar to Well No. 1

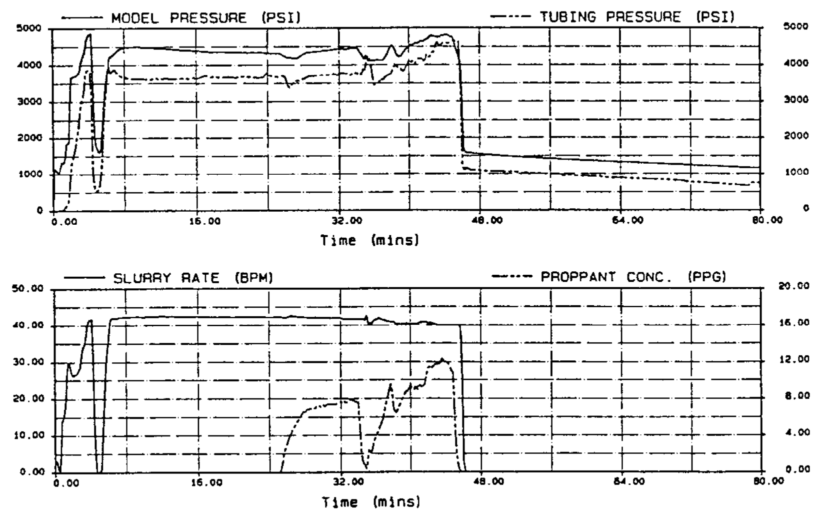


Figure 16 - Well No. 3 pressure match using stress profile from Well No. 1

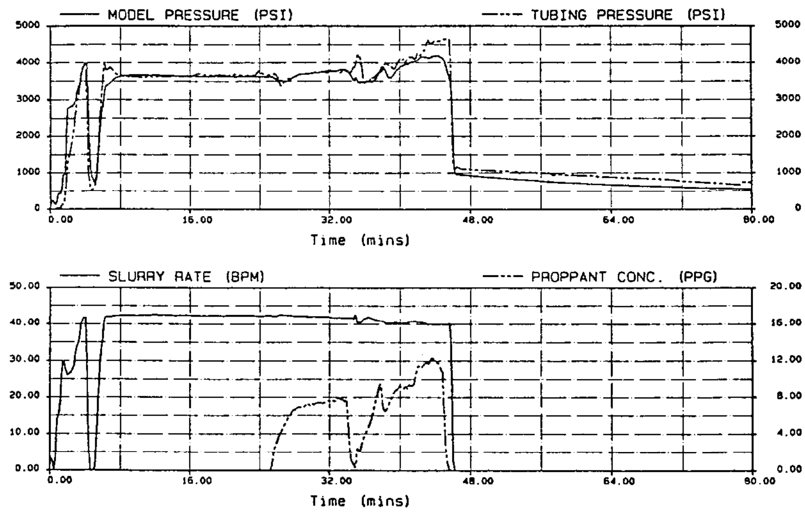


Figure 17 - Well No. 3 pressure match using modified stress profile of Well No. 1

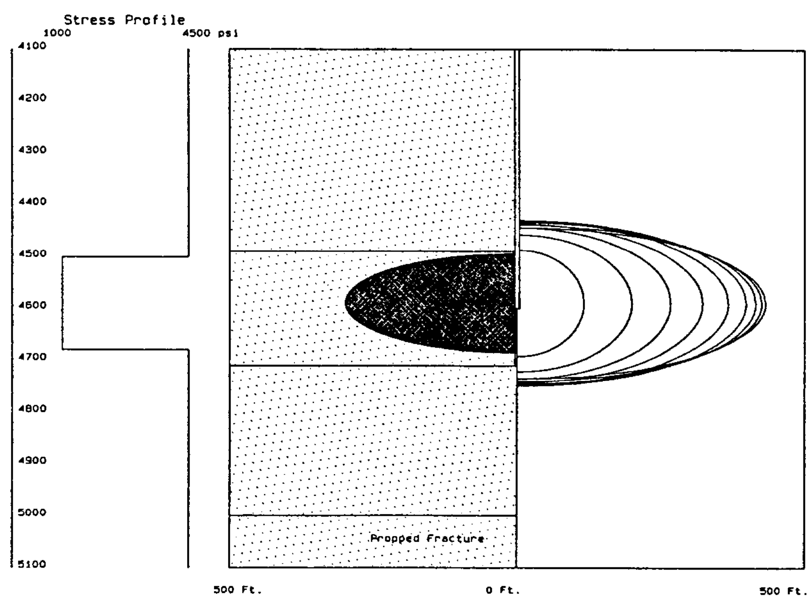


Figure 18 - Well No. 3 frac geometry using modified stress profile of Well No. 1