MEASUREMENT WHILE FRACTURING FOR COMPARING AND OPTIMIZING THE PERFORMANCE OF WELL STIMULATION TREATMENTS

Donna A. Read and Gary L. Wells
Smith Energy Services, a division of Smith International, Inc.

ABSTRACT

Analysis of Nolte Plots, the log of net fracture pressure versus log of time, can be useful in hydraulic fracturing stimulation treatments. Trends and characteristics of the formation established by these plots are being evaluated and used in an effort to optimize subsequent treatment design. This paper will present case histories on wells in the Turner formation in the Finn-Shurley field of Weston County, Wyoming and show how continuous measurement while fracturing is a useful tool in optimizing future job design.

INTRODUCTION

During the past couple of years on-site computers have made quite an impact on the hydraulic fracturing stimulation industry. This is due mainly to their potential for increasing job quality and production by optimizing future treatments. Most of the literature written on the application of on-site computers focuses on the information gathered during and after pre-fracturing treatments. While this information does facilitate and produce increased job quality and production by optimizing treatment design, it's not always cost effective for marginal wells. Useful data is also generated during fracturing via the Nolte plots.[1,2,3] These plots of log net fracture pressure versus log pumping time not only give real-time data but help characterize and define critical periods during a treatment in areas where one type of treatment is used consistently. This paper will present case histories showing how Nolte plots can be used for fracturing treatment optimization. The authors assume the reader is familiar with the Nolte-Smith modes of fracturing and their significance. Please refer to figure 1 for quick reference.

The Finn-Shurley Field, located in the northeastern corner of Wyoming, contains a depleted reservoir with the Turner being the primary producing formation. Fracturing treatments have undergone tremendous change since the discovery of the field, with operators seeking the most economical and effective stimulation treatment. Treatments today consist of 67,000 gallons of water external polyemulsion fluid, 2/3 oil and 1/3 gelled 3% KCl water, to carry 135,000 pounds of sand at 20 BPM. Table 1 shows a typical treatment schedule. This type of treatment was used during the 1983 drilling and completion program with fairly satisfactory results. Initial production rates average 55 BOPD. However, because of depleted reservoir pressure production rates decline rapidly. In 1984, the treatment schedule was evaluated to determine if and where it could be optimized. Job size, pumping rates, sand and staging volumes were analyzed. New wells were monitored while fracturing with the computer van. Trends and characteristics were analyzed and a revised treatment schedule recommended.

FINN-SHURLEY FIELD

The first well in the Finn-Shurley Field was drilled in 1963. Production from the Muddy formation was being sought after earlier finds in this formation up in the Mush Creek and Skull Creek fields to the north. The Muddy proved to be uneconomical. The Turner formation, however, did prove to economical following hydraulic fracturing treatments. Since that time over 400 wells have been drilled into and produce from the Turner. Turner oil is a paraffinic, green, 41 degree API crude. Gas is also being produced from this formation.

Geology

The Turner formation is a very fine grained sandstone, highly glauconitic, with shale stringers interbedded thoughout the sandstone. The sand grains are well cemented with a matrix containing some calcareous material. The reservoir, formed by a stratigraphic trap, has a naturally occuring permeability pinch-out up-dip to the east end as it approaches the Black Hills uplift. The Sage Breaks shale above and Carlile shale below also form a trap containing the formation fluids.

Permeability in the Turner ranges from less than 0.5 md to over 10md. The shale interbedding throughout the Turner generally yields production rates comparable to that of a much lower permeable reservoir. The reservoir also contains naturally occuring fractures. Porosity in the Turner varies between 10 to 19 percent with some secondary porosity.

Stimulation History

The Turner formation upon completion generally yields no production. Therefore, hydraulic fracturing treatments are needed to stimulate the reservoir. Initial treatments were small and consisted of only lease oil and surfactant to carry 2000-5000 pounds of sand. As larger treatment were designed a different type of fluid with a higher viscosity was needed to carry larger volumes of sand.

A spearhead of 15% HCl followed by gelled brine water was the next type fracturing treatment used. The sand carrying capacity of the fluid increased drastically and sand volume was increased to 40,000 pounds of 20-40 mesh sand and 20,000 pounds of 10-20 mesh sand. Rates varied between 10 to 15 BPM. This treatment resulted in higher initial production,but unfortunately, production declined rapidly.

Crosslinked gelled water yielded an even higher viscosity allowing for placement of more sand. Spearheading acid was discontinued because of fines being released and both job size and pumping rates were increased. Pumping rates reached as high as 55 BPM. Initial production from this treatment was similar to that of the gelled water, with slightly lower decline rates.

In 1981 operators began looking at lease oil once again as a treating fluid. Several gelled oil and water-oil emulsion treatments were pumped. These treatments further improved decline rates with initial production comparable to previous treatments. They were also much more economical since all of the lease oil injected is recoverable. Eventually it was decided that the water-oil emulsion treatment was perferable. Essentially this is the same type of treatment used today. Pumping rates have been significantly reduced to 20 BPM to attempt to limit height growth and increase penetration.

CASE HISTORIES

Initial Treatments

Radioactive and temperature survey logs were run during the 1983 program to determine the fracture height being achieved with the initial fracturing treatment. The Turner formation has an average net height of 50 to 60 feet. Therefore, the initial treatment had to produce enough height to adequately drain this producing formation. It was decided that the initial pumping rates and fluid volumes (ie.,...20 BPM and 67,000 gallons) did produce sufficient fracture height and penetration. The treatment schedule and sand volumes were considered next.

As the 1984 fracture program got underway, enough jobs were monitored by the computer van until definite trends were observed. Analysis of these plots revealed several consistent and definite trends. These events are noted accordingly in figures 2 and 3 by the following sections.

1. Confined height growth and unrestricted extention out into the formation were occurring during the 1/2 and 1 pound per gallon sand stages. (Pound per gallon shall be abbreviated as ppg.)

2. Once the 2 ppg sand stage was on formation, a period of constant net fracture pressure was observed.

3. A period of increasing net fracture pressure immediately following section 2.

4. Once the 3 ppg sand stage was on formation, another period of constant net fracture pressure was observed.

5. A period of unstable height growth was observed during the later part of the 3 ppg and early part of the 4 ppg sand stages.

Sections 2 and 4 were the most significant trends observed during the initial evaluating phase of the study. These periods of constant net fracture pressure are known as Nolte's Mode II of fracturing and were followed by either a pressure increase, as in section 2 or a pressure decrease, as in section 4. Since the Turner is naturally fractured, section 2 was most likely caused by leakoff. Leakoff to the natural fractures would cause a reduction in fluid velocity in the fracture, accelerating proppant deposition. This would have magnified what was already occurring in the fracture with a fracturing fluid such as WEP (water external polyemulsion)[4], a sand banking fluid.

Sand laden WEP[4] props the formation open by forming a bank of proppant in the fracture. As bank height increases in the fracture, flow becomes restricted above the bank. This probably accounts for the sudden increase in net fracture pressure immediately following section 2. Sand continues to settle, futher restricting fluid flow until an equilibrium velocity across the bank is achieved. At this point, the bank ceases to grow in height and begins growing in length. Fluid flow across the top of the bank stabilizes, causing the net fracture pressure to be fairly constant. This may be what is happening in section 4. Fracture height, caused by higher net fracture pressures, could also be increasing, which would in turn cause the sharp reduction in net fracture pressure in section 5. Both may have contributed to the constant pressure period. No definite trends were established after section 5.

Treatment Revisions

Nolte plot analysis indicated that leakoff and insufficient fracture height would prevent major changes in sand volume before equilibrium bank height was achieved. The increase in net fracture pressure seemed to eventually produce some fracture height growth, enabling more sand to be placed in the formation. This usually happened shortly after the 3 ppg sand stage was on formation. To increase fracture conductivity, sand volumes would have to be increased after this point. In order to accomplish this, sand stages were increased by 1/2 ppg increments instead of the previous 1 ppg increments. The maximum sand concentration was also increased to 6 ppg. This essentially kept fluid and sand volumes the same up until the start of the 3 ppg sand stage. In effect, this increased the propped width near the wellbore and probably resulted in improved fracture conductivity. Table 2 shows the revised treatment schedule.

A Nolte plot produced from the revised treatment is shown in figure 4. Initial trends up through the 3 ppg sand stage on formation were basically the same. This was expected since very little was changed during the early part of the treatment. The major change observed was a relatively long period of constant net fracture pressure occurring after the 3 1/2 ppg sand stage was on formation. This may indicate equilibrium bank height was reached and the bank was growing in length. There may have been a slight amount of height growth late in the 4 ppg sand stage. Overall, the total amount of sand placed in the formation was increased an average of 10,500 pounds, with the fluid volume essentially the same.

SUMMARY

Nolte plot analysis was used to optimize the stimulation treatments being used on the Turner formation in Finn-Shurley field, Weston County, Wyoming. New wells drilled in the field result in marginal production. Therefore, stimulation treatments must be as effective as possible. Job size and pumping rate were considered adequate for providing sufficient height and penetration needed to effectively stimulate the reservoir. Based on trends seen on the Nolte plots, the treatment schedule was revised to hopefully improve fracture conductivity at the wellbore and increase the effective wellbore radius. This was done by changing the sand stage increments from 1 ppg to 1/2 ppg, thereby increasing the total amount of sand being placed in the

reservoir, ie.,...145,500 pounds compared to the previous 135,000 pounds, for a net increase of 10,500 pounds. The cost for the extra sand was minimal.

Nolte plots indicated sand volume could not be increased until after the sand banking effect created more fracture area by increasing the net fracture height. This point marked the turning point in the initial treatment. Nolte plots for wells stimulated with the revised treatment had a relatively long period of constant net fracture pressure once the 3 1/2 ppg sand stage was on formation. Refer to figure 4. This seems to be indicative of sand banking fluids after the equilibrium height bank is achieved. The best indicator, showing which of these treatments will prove out, will be the their respective production histories. Unfortunately, at the time of this writing, a sufficient amount of time hasn't elapsed to see any significant differences between the two treatments.

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Table 1
Initial Treatment Schedule

STAGE	SAND CONC. (ppg)	STAGE VOL. (gallons)	CUMM. VOL. (gallons)	STAGE SAND (pounds)	CUMM. SAND (pounds)
Pre-Pad 3% KCL Water	0	3,000	3,000	0	0
Pad (Wep)	0	15,000	18,000	0	0
1	1/2	4,000	22,000	2,000	2,000
2	1	10,000	32,000	10,000	12,000
3	2	10,000	42,000	20,000	32,000
4	3	10,000	52,000	30,000	62,000
5	4	12,000	64,000	48,000	110,000
6	5	5,000	69,000	25,000	135,000
Spacer	0	500	69,500	0	135,000

Table 2
Revised Treatment Schedule

STAGE	SAND CONC. (ppg)	STAGE VOL. (gallons)	CUMM. VOL. (gallons)	STAGE SAND (pounds)	CUMM. SAND (pounds)
Pre-Pad 3% KCL Water	0	3,000	3,000	0	0
Pad (Wep)	0	15,000	18,000	0	0
1	1/2	7,000	25,000	3,500	3,500
2	1	5,000	30,000	5,000	8,500
3	1 1/2	4,000	34,000	6,000	14,500
4	2	4,000	38,000	8,000	22,500
5	2 1/2	4,000	42,000	10,000	32,500
6	3	7,000	49,000	21,000	53,500
7	3 1/2	5,000	54,000	17,500	71,000
8	4	5,000	59,000	20,000	91,000
9	4 1/2	5,000	64,000	22,500	113,500
10	5	4,000	69,000	20,000	133,500
11	6	2,000	72,000	12,000	145,500

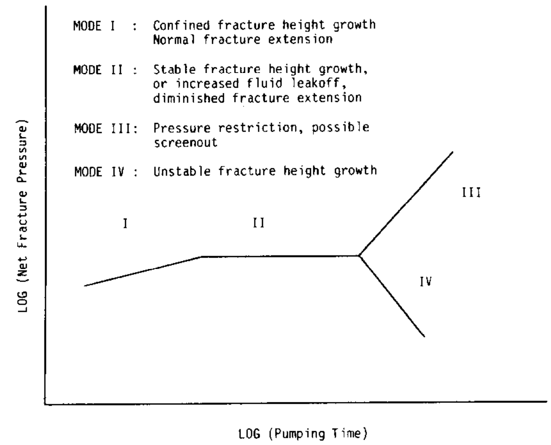

Figure 1 - Nolte-Smith modes of fracturing

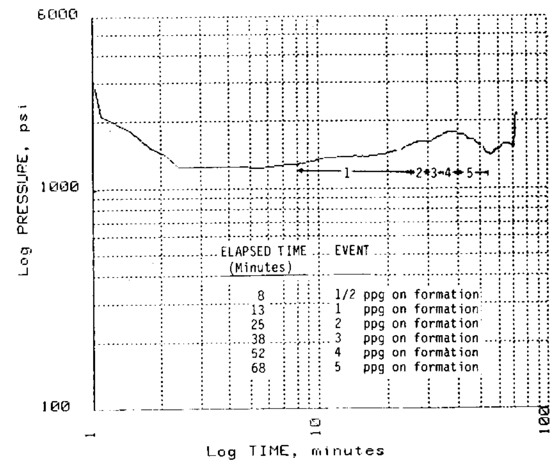

Figure 2 - Initial treatment
(net fracture pressure vs. time)

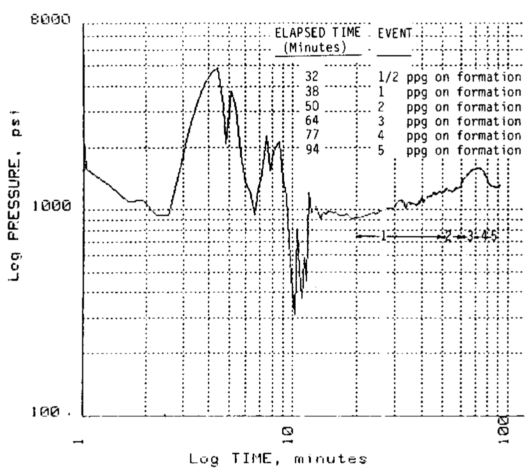

Figure 3 - Initial treatment
(net fracture pressure vs. time)

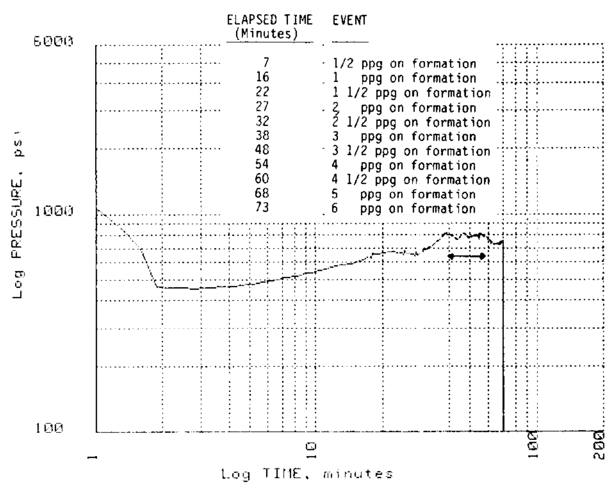

Figure 4 - Revised treatment
(net fracture pressure vs. time)