IMPROVING STIMULATION RESULTS WITHIN CARBONATE FORMATIONS BY EXTENDING LIVE ACID PENETRATION

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ABSTRACT

Carbonate formations are often stimulated by hydraulically fracturing the zone of interest with reactive fluids, most commonly hydrochloric acid. The productivity increase of the oil and gas wells where this stimulation approach is utilized, is often much less than predicted by the pretreatment design.

This paper will address the problems and difficulties of properly designing an acid fracturing stimulation treatment, and will offer new techniques and alternative fluid systems that allow better designs for this type of stimulation. These new methods and fluids have recently been applied to achieve extended fracture penetration of live acid into carbonate formations, allowing higher sustained production. Results of treatments where the new designs have been utilized throughout the Permian Basin will be included as case histories.

INTRODUCTION

Hydraulically fracturing with acid is a known and effective means of stimulating oil and gas bearing zones within carbonate formations. This method of stimulation has been utilized for over fifty years. Much of the popularity of this means of stimulation lies in the inherent simplicity of the operation. Some of the simple advantages over fracturing with proppants are as follows: 1) Materials do not need to be added at precise concentrations on the fly, as is necessary with the addition of proppant; 2) With the proppant being eliminated there is no risk of failing to complete the scheduled treatment due to screenouts; 3) There is no proppant flowback problem after the treatment which could cause pump problems on the well; 4) Theoretically, the conductivities which are obtained should be much higher, especially at low to moderate closure pressures.

The actual success of a fracture acidizing treatment depends on the two dominant factors of conductivity and fracture length. To establish a conductive flow path, the acid must create an etch pattern along the fracture face, which will result in an area of improved conductivity as the fracture closes. The resulting amount of conductivity depends on the amount of material dissolved and removed from the formation, and the irregularity of the etched pattern along the fracture faces. As the two roughed fracture faces close back together after the treatment, a highly conductive flow channel remains, because the roughness prevents complete closure.

The fracture length, or penetration distance of "live acid" (ie. acid of sufficient strength to dissolve carbonaceous material) away from the wellbore, is controlled by the reaction rate of the acid and the fluid efficiency of the hydraulic fracturing system. In general, wells which have a bottom hole temperature below 150°F have limited penetration due to low fluid efficiencies, while wells with bottom hole temperatures above 200°F are limited by the acid spending rate.

The fluid efficiency of any fluid used in hydraulic fracturing is determined by the rate of fluid being injected into the fracture, and by the rate of fluid leaving the fracture due to fluid loss. In the case of reactive fluids, the fluid loss is enhanced by flow channels which the acid creates as it spends in the fracture. When the pore throats of the rock along the fracture face are exposed to acid, the largest pores will allow acid to enter and leak off. The acid will dissolve the rock within this pore and enlarge the pore. This becomes a self feeding phenomenon which creates a flow channel, often referred to as a "wormhole", perpendicular to the fracture face. The same type of self feeding reaction will also take place at other points of high leakoff, such as natural hairline fractures. As these newly created flow channels become larger and larger, a greater surface area is created which will be available for fluid leakoff. With a surface area many times greater than that of the original fracture face contributing to the leakoff of the acid, penetration rapidly becomes limited.

The reaction rate is a measurement of how fast the acid spends on carbonaceous material. Under fracturing conditions, there are several parameters controlling the effective spending rate. First, the mineralogical composition of the rock is a major factor. The closer the mineralogy is to a pure calcium carbonate or limestone ($CaCO_3$), the faster the acid will spend. As other ions are substituted or replace the calcium ions, such as in dolomites $CaMg(CaCO_3)_2$, the reaction begins to slow. The temperature of the acid and the formation will also greatly impact the reaction rate, with an increasing spending rate corresponding to an increasing temperature. Similarly, concentration of the acid will also correspond to spending rate, with an increase in concentration creating a faster spending rate. During an actual treatment, other parameters such as injection rate, fracture width, and volume of acid pumped, will impact the rate at which the acid will spend.

Ultimately these parameters controlling the spending rate will control the fracture length. During a treatment, acid is constantly reacting with the fracture surfaces, and is decreasing in strength. At some point the acid will reach a concentration which is no longer capable of dissolving enough carbonate material to create a significant etch pattern. A concentration of 10% of the original concentration has long been accepted to be a point at which the etching will become so slow that fluid loss will occur before significant etched width will be made.[1]

CURRENT METHODS USED FOR INCREASING ACID PENETRATION

There are several techniques currently used to increase the penetration of acid away from the wellbore. These range from pumping a viscous pad ahead of the acid, or gelling the acid itself, to retarding the actual spending rate of the acid. In practice, it is common to combine some of these techniques in an attempt to obtain even further penetration of the acid.

- Viscous Pads

  The injection of a nonreactive viscous pad ahead of the acid is one of the most common methods used for increasing live acid penetration. The advantages of this method of stimulation may be attributed to several reasons. First, the viscous fluid creates a much wider fracture than when starting the treatment with acid. The increased width results in an improved volume-to-surface-area ratio when the acid enters the fracture. This allows a larger percentage of acid to be within the increased volume of the fracture, and not in contact with the formation face where it would be spending. The pad fluid will also provide a cooldown effect within the fracture which will slow the reaction rate of the acid. Another benefit of initiating an acid treatment with a viscous pad is that this type of fluid lays down a compressible filter cake on the fracture faces. The filter cake material will prevent the following acid from immediately contacting the rock face.

The other benefits of this technique are based on the viscosity difference between the pad fluid and the acid. The acid viscosity is much lower than that of the pad and will tend to finger into the pad rather than completely displace it in a piston-like manner. This phenomenon decreases the amount of reactive surface area to which the acid is exposed. This will result in an increased velocity along the fracture face for the acid phase, and will therefore increase the fluid efficiency of this stage. Also, due to the fact that the acid is now occupying only a portion of the fracture volume, the penetration should increase over the contacted area. With more acid flowing over a smaller portion of the created fracture, more rock will be removed along this selective fingering area, which will result in an increase in the effective conductivity of the etched fracture.

- Gelled Acids

The use of gelled acids has dramatically increased over the past few years. These acid systems are viscosified from a variety of materials, including acrylamides, xanthans, and surfactant gels. In addition to the advantages of increased width, it has been a common belief that the increased viscosity reduces the rate of mass transfer at the fracture wall, by slowing down the convection forces. Early research, performed at static conditions, indicated good retardation from these systems. Recent research performed under dynamic conditions indicates that these systems have only minimal retarding effects, and may at times actually increase the reaction rate.[2] This is most likely due to the way the gelled fluid removes the reaction products from the formation face.

- Retardation

The easiest way to decrease the reaction rate of an acid is to simply utilize the natural by-products generated from the reaction. The general reactions of hydrochloric acid with limestone and dolomite are:

$$CaCO_3 + 2HCl \rightarrow CaCl_2 + H_2O + CO_2 \tag{.1}$$

$$CaMg(CO_3)_2 + 4HCl \rightarrow CaCl_2 + MgCl_2 + 2H_2O + 2CO_2 \tag{.2}$$

To utilize these created by-products to retard reaction rate, the initial concentration of the acid would simply be increased. The reaction rate of an acid with an initial concentration of 15% HCl is almost twice as fast as a 15% acid which had an initial concentration of 28% and has spent down to the lower concentration. This slowing of the reaction rate is due to the reaction products entering the solution as the acid spends.

One of the earliest methods used to retard the reaction rate of acid was to add oil-wetting surfactants such as alkyl sulphonates, alkyl phosponates, or alkyl amines to the acid. When the retarding surfactant combined with oil from the formation, an oily film barrier was layed down on the rock face. This oily barrier would protect the carbonate material from attack by acid in a manner similar to the way corrosion inhibitors protect steel surfaces. Some of these surfactant retarders will also form a stable foam from the CO_2 which is liberated as a reaction product. This stable foam can form a layer on the rock face which can act as a physical barrier, preventing the acid from making contatct.

The introduction of surfactants and a gas to create a foam may also show some benefit in lowering the reaction rate. The foam will have the surfactants available to allow the formation of the foam layer previously discussed. Also, being a form of an emulsion, the foam will always have two seperate phases contacting the rock face, one of which is a nonreactive gas. Foams also develop good viscosity and gain the benefits of both increased fracture width, and slower diffusion. This type of fluid will also display improved leakoff properties.

Emulsified acids have been proven to be very effective in retarding the reaction rate of acid. Both oil-outside and acid-outside emulsions have been used with good success. The oil-outside phase emulsions are the most effective, in that they inherently prevent the acid from immediately contacting the reactive surface. These fluids will also display the benefits of wider fractures due to their viscosity. The reaction rate of these fluids can be even further lowered by adding an oil-wetting surfactant.

Organic acids, such as acetic and formic, are often added to hydrochloric acid in an attempt to create a retarded acid. These organic acids do not spend to completion under the effects of pressure, and have therefore given the impression that they are retarded. These acids do not slow down the spending process of the hydrochloric acid, but do spend slower themselves. The disadvantage of using organic acids is their limited spending under confined conditions. Only 40% to 60% of these acids actually spends, limiting the amount of carbonate material they will dissolve.

- Multiple Pad Stages

  Using multiple pad and acid stages is based on much of the same methodology as described in using viscous pads to initiate a fracture ahead of acid. The main addition to this technique is that pads of viscous, wall-building, fluids are pumped ahead of acid stages in succession, in order to maintain fluid loss control of the acid portion of the systems. Once an acid stage has been completed the viscous pad comes behind to rebuild the wall cake and, more importantly, regain control of the fluid loss due to wormholing.[3] It is quite common to add solid bridging material, such as 100 mesh sand, to the subsequent pad stages to fill the wormholes which the acid has created.[4] This will create a pressure drop within the wormhole, as compared to the main fracture, and will therefore help keep the acid within the main flow down the fracture.

SIMULATION OF ACID FRACTURING TREATMENTS

Guidelines and design simulators for designing acid fracturing treatments have been available for many years. Most simulators predict overly optimistic results because of the methods used to calculate conductivity and fluid loss of an acidic fluid. To calculate conductivity, simulators are able to approximate the amount of rock removed along the walls of the fracture, and the ultimate penetration of the acid, based on reaction rates. This can be related to an etched width and ultimately a conductivity along the length of the fracture. The earliest approximations of conductivity simply related the etched width to a slot. Under these assumptions the ideal conductivity can be expressed as:

$$k_f w = 7.8 \times 10^{12} \left[\frac{w}{12} \right]^3 \qquad (.3)$$

This approach of calculating conductivity ignores closure stress effects, and is therefore very optimistic. Nierode and Kruck developed a method of estimating fracture conductivity which incorporated the effects of closure stress and rock embedment strength, to adjust the ideal etched width[5]. Novotny combined this approach into an acidizing model showing that it would be difficult to obtain adequate fracture width deep into a formation (Figure 1)[6]. Although this is an improvement, this method assumes a relatively even etch pattern, which may not occur in actual conditions with the heterogeneity of most carbonate formations. Actual conductivity numbers may lie someplace between these two extremes.

The fluid loss models used in most simulators apply the methods first developed by Carter, and expanded by Smith, which were developed for nonreactive fluids[7]. This implies that fluid loss is controlled in one of three ways, and can be related to an expression of a coefficient. The three coefficients are: C_I – fracturing fluid viscosity and relative permeability; C_{II} – reservoir fluid viscosity/compressibility effects; C_{III} – wall building effects of the fracturing fluid. These coefficients can then be combined in a manner similar to a series of electrical conductors to arrive at a C_t, or total leak off.

The fluid loss of a reactive fluid cannot be simply calculated by using the three basic coefficients to come up with a total leakoff. When acid is used during a fracturing treatment, the fracture faces are continually eroded due to the dissolving action of the acid, making it difficult for a wall cake to be formed. In addition, most of the materials which would form a wall cake are unstable in acid, and would break down before fluid loss could be controlled. The viscosity and compressibility portions of the leakoff model do not adequately predict fluid loss rates because of the dynamic wormholing process, which causes the leakoff permeability to continually increase. Even though these differences are recognized, many simulators still use this approach to leakoff calculations because of the difficulty in generating more accurate numbers. With realistic leakoff numbers for reactive fluids being difficult to generate under laboratory conditions, nonreactive fluid efficiency numbers are often substituted.

DETERMINATION OF FLUID LOSS NUMBERS

In order to establish an understanding of what actual fluid loss numbers might be, pressure decline data was gathered and analyzed after acid fracturing treatments, utilizing the methods first described by Nolte, and expanded by Castillo[8,9]. For the case of reactive fluids, the analysis must assume that the leakoff is not controlled by an incompressible filter cake, implying that leakoff is a pressure dependent variable. Figure 2 is a table showing the results of leakoff calculations for different acid systems in various reservoirs.

REAL – TIME DESIGN OF ACID FRACTURING TREATMENTS

It has become standard practice for many operators to monitor fracturing treatments with net pressure plots, as first described by Nolte and Smith, to determine the effectiveness of a propped fracturing treatment during pumping.[10] As the industry has gained confidence in the real-time analysis of this plot, fracturing treatments are now redesigned in the field based upon this information. These plots have been most useful in predicting when treatments must be aborted prematurely due to screenouts, or in predicting when height growth may be a problem.

These plots have five characteristic modes which will define how the fracture is extending when net pressure is plotted against time on log-log coordinates. Mode I will characteristically show a response of an ever increasing net pressure at a slope between one quarter and one eighth. This indicates that the fracture is extending and the fracture height is contained. The increasing pressure is given by:

$$w \propto \left[\frac{(\mu q L_f d)}{(E' h_f)} \right]^{.25} \tag{.4}$$

$$\Delta p \propto \frac{E' w}{d} \tag{.5}$$

where w is the width of the fracture, μ is the viscosity of the fracturing fluid, q is the pump rate, L_f is the fracture half-length, d is the dimension of failure elipse, E' is the plain strain modulus, h_f is the fracture height, and Δp is the net pressure within the fracture.[11] Mode II is characterized by a flat slope, and is indicative of subtle height growth at the wellbore, or the opening of natural fissures. Mode IIIa is defined by a positive unit slope, and indicates that proppant has reached the tip of the fracture and is now restricting extension. Mode IIIb indicates that extension of the fracture is still limited, but only one wing of the system is accepting fluid. Mode IV is characterized by a negative slope, and will be found when there is unrestricted height growth through the stress boundaries.(Figure 3)

There has been little use of the diagnostic net pressure plot during acid fracturing treatments, because there is no risk of screen out. However, when this diagnostic approach is utilized during an acid treatment, much can be determined about the successfulness of the treatment. The plot of net pressure on these treatments will usually go into Mode IV soon after acid is on formation. For the case of reactive fluids, this negative slope may not always indicate an increase in fracture height, but rather show that this fluid has reached a point of astronomic leak off, and is no longer extending. The dominant leakoff will result in a narrower width, and therefore the negative slope.

By recognizing the negative slope on the net pressure plot, it is possible to determine the optimum volume of acid to be pumped on a treatment. Any acid that is pumped into the fracture after this point will only create further wormhole development, and will not contribute to fracture length. Without creating greater fracture length, the additional acid will not significantly contribute to increased production. To gain control over the leakoff, a subsequent viscous pad can be pumped. This second pad fluid must be large enough that a continued positive trend can once again be developed on the net pressure plot[12]. Acid can then be introduced into the fracture again, and pumped until a second negative slope becomes dominant. This cycle can be repeated several times, as long as a continued positive trend is established, as shown in figure 4.

CASE HISTORY RESULTS

The following case histories detail production increases when using real-time pressure analysis to control acid fracturing designs:

1. San Andres formation; Yoakum County, Texas. Depth = 5200 ft.
    - The treatment consited of a 2000 gallon prepad of gelled water with 100 pounds of gelling agent per thousand gallons. This was followed by a 3000 gallon pad of crosslinked gelled

water. 28% hydrochloric surfactant gelled acid was then alternated with gelled water stages carrying 100 mesh sand. The entire treatment was pumped at 5 BPM.(Figures 5 & 6)

Production Before	*Production After*
32 BOPD	142 BOPD - Initial
	80 BOPD - 28 months

2. Clearfork formation; Yoakum County, Texas. Depth = 7000 ft.
   - This formation was treated using alternating stages of gelled water and 15% surfactant gelled hydrochloric acid, at an average rate of 17 BPM. The pad stages contained 100 mesh sand for fluid loss control.

Production Before	*Production After*
15 BOPD	106 BOPD - Initial
2 BWPD	29 BWPD
	106 BOPD - 60 days
	21 BWPD

3. San Andres formation; Hockley County, Texas. Depth = 5000 ft.
   - Treatment of this well was done at an average of 5 BPM, using alternating stages of surfactant gelled acid and crosslinked 30 pound gelled water. 100 mesh sand was used for the fluid loss additive.(Figure #7)

Production Before	*Production After*
5 BOPD	22 BOPD
11 BWPD	50 BWPD

4. Devonian formation; Andrews County, Texas. Depth = 9000 ft.
   - The treatment had alternating stages of crosslinked gel containing 100 mesh sand and an oil outside phase emulsified acid. The acid strength was 20%, and the treatment was pumped at 20 BPM.

Production Before	*Production After*
65 BOPD	153 BOPD - Initial
	120 BOPD - 2 weeks

CONCLUSIONS

1. In the low temperature carbonate reservoirs of the Permian Basin, the problem of excessive fluid loss is the greatest single limiting factor in creating a deeply penetrating fracture with a reactive fluid.

2. Leakoff and efficiency values for reactive fluids in carbonates reservoirs, calculated under field conditions, are much higher than those numbers determined under laboratory conditions for nonreactive fluids.

3. Real-time design of acid fracturing, through the use of net pressure analysis, is necessary to optimize the volume of acid pumped.

4. Production can be improved by combining real time design analysis, multiple pad stages, and conventional retarded acids.

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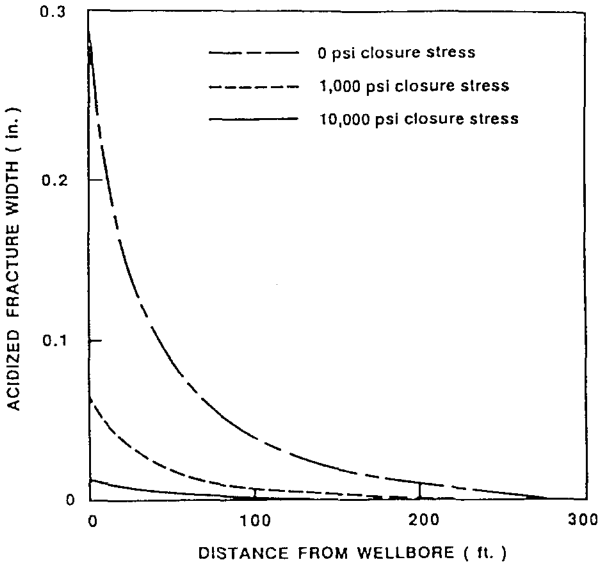
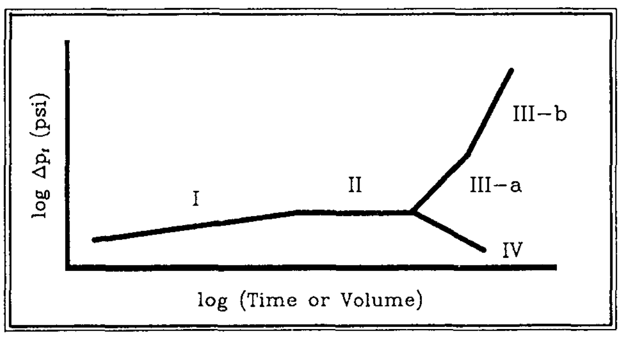


Figure 1 — Acidizing fracture width as a function of the distance from the wellbore and closure stress (from Novotny, 1977)

Acid System	Formation Name	Fracture Height (ft.)	Fracture Penetration (ft.)	Leakoff Coefficient ($ft/min^{.5}$)	Fluid Efficiency (%)
Foamed Acid	Cisco Lime	80	70	.017	1.2
Multiple Pads and Emulsified Acid	Devonian	275	211	.005	16.0
Multiple Pads and Emulsified Acid	Devonian	271	140	.006	21.0

Figure 2 — Leakoff properties



Slopes of Fracturing Pressures and Their Interpretation		
Mode	Approximate Log–Log Slope Value	Interpretation
I	1/8 to 1/4	Restricted Height and Unrestricted Extension
II	0	a) Subtle Height Growth b) Fissure Opening
III–a	1 : 1	Restricted Extension (Two Active Wings)
III–b	2 : 1	Restricted Extension (One Active Wing)
IV	Negative	Unrestricted Height Growth

Figure 3 — Idealized net pressure data

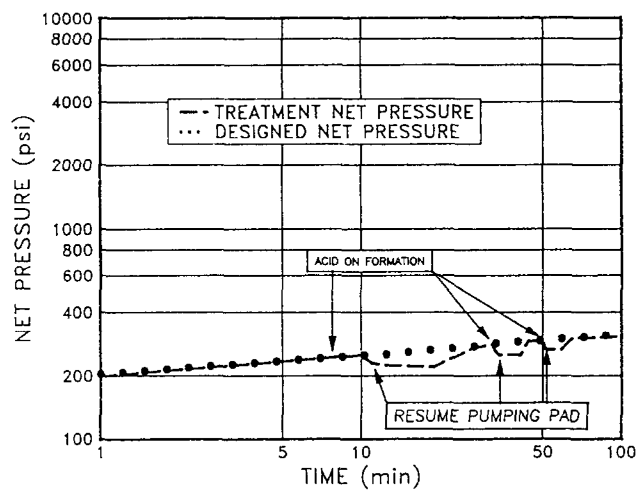


Figure 4 — Typical net pressure response with alternating pad and acid stages

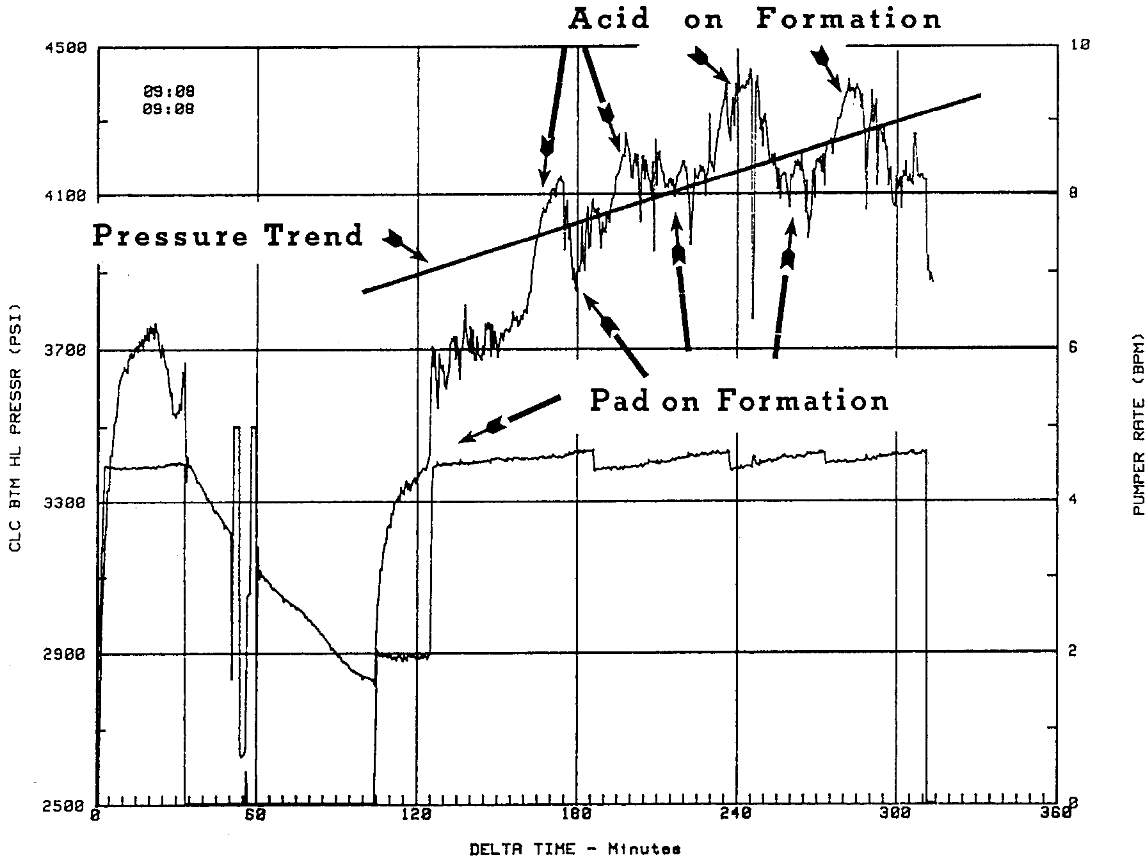


Figure 5 — Treatment history — San Andres formation — Yoakum County, Texas

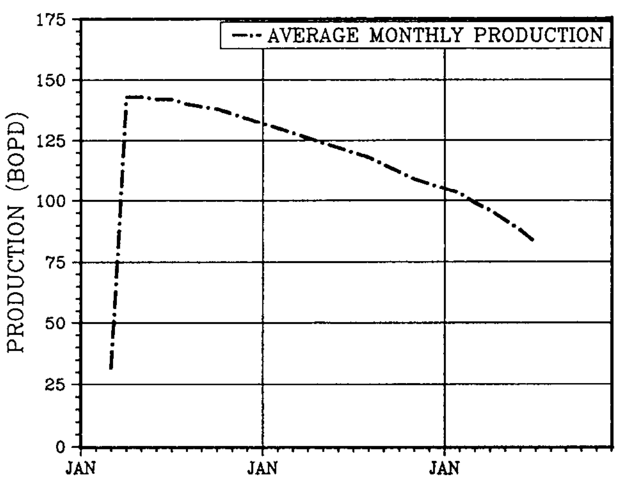


Figure 6 — Average monthly production San Andres formation Yoakum County, Texas

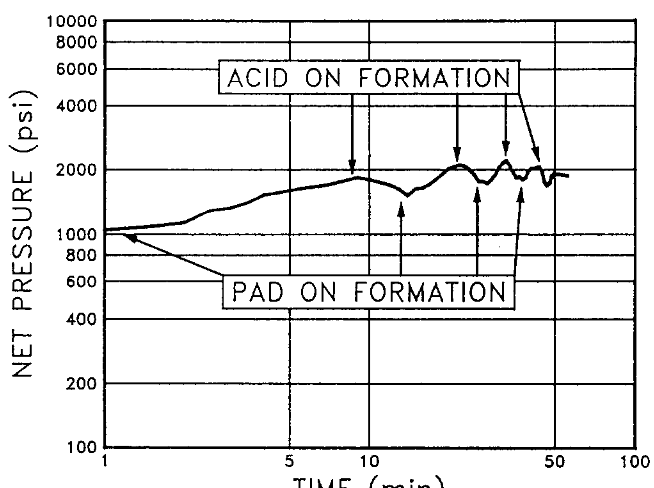


Figure 7 — Treatment on San Andres formation