MINI MASSIVE FRAC

FOR HIGH, SUSTAINED PRODUCTION GAINS

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ABSTRACT

The Mini Massive Frac is a technique designed for stimulating low porosity, low permeability formations. It allows for placing high concentrations of sand in the hydraulically induced fracture by limiting fluid loss. The technique also utilizes cross-linked polysaccharide derivative fracturing fluids to provide a uniform distribution of proppant. Since its' introduction to the Permian Basin, the Mini Massive Frac has been used to treat more than 150 wells, with considerable success.

This paper describes the design characteristics of the Mini Massive Frac technique. Emphasis will be given to field case histories showing sustained production increases typical of these treatments. Also discussed is the use of 100 mesh sand for leak-off control, and high viscosity fluids for greater sand carrying capabilities.

INTRODUCTION

In a paper presented at the 1977 Society of Petroleum Engineers Eastern Regional Meeting, Warren L. Crow described a new technique for stimulating low porosity, low permeability formations, which he called the "Mini Massive Frac."[3] Because of the consistantly superior results obtained in the Appalachin area, using this technique over conventional techniques, the Mini Massive Frac was introduced and adopted in the Permian Basin by Richard Royal to meet specific needs and to incorporate newly developed technology. Since it's introduction to the Permian Basin, more than 150 wells have been successfully stimulated using the Mini Massive Frac technique.

The Mini Massive Frac is a hydraulic fracturing technique, which utilizes high concentrations of proppant. Two systems are presently being used. The one system uses a maximum of 6 PPG 20/40 mesh sand (5 PPG average concentration), with a tail-in of 6 PPG 10/20 mesh sand to give maximum conductivity at the wellbore. The second system uses a maximum concentration of 9 PPG 20/40 mesh sand (8 PPG average), with 9 PPG 10/20 mesh sand tail-in.

The placement of high sand concentrations in an induced fracture requires optimum control of fluid loss away from the main fracture. The Mini Massive Frac utilizes two fluid loss mechanisms.

100 mesh sand is used to control leakoff of fracturing fluids to natural fractures. This fine mesh sand enters the natural fractures and bridges, forming an artificial matrix and reducing the conductivity of these fractures. Because the conductivity of a packed fracture is less than that of an open one, the loss of fluid to these secondary fractures is slowed considerably. Once these "Mini" sand packs are established, the fluid loss can be further controlled by the wall building characteristics of the polysaccharide derivative (PSD) gels used in the Mini Massive Frac technique. These fluids will deposite a thin filter cake along the walls of the main fracture and against the 100 mesh sand packs, thus reducing the rate at which fluid leaves the main fracture and enters the formation. By keeping the fracturing fluid in the main fracture, fracture penetration is enhanced and the possibility of screenout is reduced.

Besides providing fluid loss control by the deposition of a filter cake, the PSD fluids also provide an excellent medium for the transport of high sand concentrations. The most commonly used fluids are those made with 20 and 30 pounds of PSD gelling agent per 1000 gallons of water. These fluids are crosslinked to produce very high viscosities, ranging from 250 cps. to over 500 cps. at 80°F. The high viscosity provided by the crosslinked PSD fluids allows for the creation of wide fractures and the placement of proppant, with a minimum amount of proppant settling.

DESIGN CRITERIA

In the design of Mini Massive Frac treatments, fluid volumes and fluid injection rates are based on the gross height (H_g) of the zone to be fractured. Fluid volumes will also vary according to the drainage radius of the well. The following volumes are presently recommended:

Fluid Volume	Drainage Radius
2000 gal/10 ft. H_g	20 acre
3000 gal/10 ft. H_g	40 acre
4000 gal/10 ft. H_g	60 acre

These fracturing fluids are injected at rates varying from 1 BPM to 1.5 BPM per 10 ft. of gross height. Where clear barriers do not exist, above and below the zone of interest, fracture height can often be controlled by using these reduced injection rates. Radioactive tracer surveys run after the treatment of a number of wells in Crane, Ector, Winkler and Ward Counties indicated that fracture heights developed in sandstone formations ranged from 8 to 10 ft. per BPM injection rate. In the limestone formations, the fracture heights varied from 4 to 6 ft. per BPM.

The two Mini Massive sytems presently in use in the Permian Basin are defined as follows:

6 PPG System

Average Sand Concentration	Mesh Size	Function
3 PPG	80-140	Leakoff Control
5 PPG	20-40	Proppant
6 PPG	10-20	Tail-in

9 PPG System

Average Sand Concentration	Mesh Size	Function
4 PPG	80-140	Leakoff Control
8 PPG	20-40	Proppant
9 PPG	10-20	Tail-in

Both of these systems use crosslinked PSD fluids to transport the proppant and control fluid loss to the rock matrix. The 6 PPG system generally uses a crosslinked PSD fluid containing 20 pounds of PSD gelling agent per 1000 gallons of water. For the 9 PPG system, a crosslinked fracturing fluid containing 30 pounds of PSD gelling agent per 1000 gallons of water is used. The last 500 gallons of fluid is sometimes run without crosslinker in order to obtain a screenout of the 10/20 mesh sand at the wellbore and provide maximum fracture conductivity near the wellbore.

CASE HISTORY #1

The first Mini Massive performed in the Permian Basin was on a well in the McElroy field, Crane County, Texas. This was a new well, with cased hole completion and perforations in the San Andres formation. The well was fractured using 15,000 gallons of crosslinked PSD fluid (20 pounds of gel/1000 gal water) at 20 BPM. This was a 6 PPG system, using:

17,000 lbs of 100 mesh sand

33,000 lbs of 20/40 mesh sand

5,000 lbs of 10/20 mesh sand

The job was performed in August of 1978 and the initial response showed 70 BOPD and 1000 BWPD production (Fig. 1). By October of 1978, production had stabilized at 150 BOPD.

CASE HISTORY #2

This well is located in the North Ward Estes field, Winkler County, Texas. It is a cased hole, with six perforations in the

Yates formation from 2817 to 2934 feet. The well was treated with 18,000 gallons of crosslinked PSD fluid (30 pounds of gel/1000 gal water) at 12 BPM. This was a 9 PPG system, containing:

25,200 lbs of 100 mesh sand

72,000 lbs of 20/40 mesh sand

10,800 lbs of 10/20 mesh sand

The normal response to conventional fracturing treatments in this area is 50 BOPD. This well cleaned up and produced 120 BOPD.

CASE HISTORY #3

This well is a 200 foot open hole completion of the San Andres formation. It is located in the McElroy field, Crane County, Texas. The well was treated with two stages of crosslinked PSD fluid (20 pounds of PSD gelling agent per 1000 gal water) at 20 BPM, with a 500 pound block of a chemical diverter dropped between stages. Each stage consisted of 15,000 gal of fluid with sand in concentrations up to 6 PPG.

Production on this well went from 12 BOPD and 3 BWPD before the treatment to 80 BOPD after treatment. The job was performed in May of 1979. As of January 22, 1980, this well was still producing 127 BOPD and 20 BWPD.

CASE HISTORY #4

This well is located in the Gomez field, Pecos County, Texas. Sixteen perforations were shot in the Queen Sand formation from 3200 to 3380 feet. The formation was fractured with a 9 PPG Mini Massive system. 30,000 gallons of crosslinked PSD fluid (30 pounds of gel/1000 gal water) was used, with 48,000 lbs of 100 mesh sand, 96,000 lbs of 20/40 mesh sand and 18,000 lbs of 10/20 mesh sand as a tail-in. The treatment was performed in two stages at 14½ BPM down 4¼ inch OD casing.

The well was treated on November 1, 1979. On November 7, 1979, the well showed a potential for 93 BOPD on a 16/64" choke. Eleven weeks later, the well was still flowing 93 BOPD on a 16/64" choke. Normally, wells in this area show post stimulation potentials of 20 to 120 BOPD, pumping. Three months after treatment, production typically declines to about 50% of the original response.

CASE HISTORY #5

This was a new well in the McElroy field, Crane County, Texas. It was perforated from 3658' to 3886', with fifteen holes in the San Andres formation. The treatment consisted of 30,000 gallons of crosslinked PSD fluid (20 pounds of gel/1000 gal water) pumped at

23 BPM. This was a 6 PPG system, with total sand volumes of:

34,000 lbs 100 mesh sand

66,000 lbs 20/40 mesh sand

9,600 lbs 10/20 mesh sand

Figure 2 shows the production response to this treatment. Although production does decline after stimulation, that decline is much less than would normally be seen in this area. As of January 22, 1980, the well was still producing at a rate of 35 BOPD and 52 BWPD.

DISCUSSION

The use of 100 mesh sand to control leakoff of fracturing fluids to natural fractures and other sources of secondary porosity, thus improving penetration and reducing the possibility of screenout, was first proposed by B. D. Miller and P. A. Warembourg in 1975.[5] They pointed out that secondary fractures, whether natural or induced, can cause rapid leakoff of fracturing fluids away from the main fracture. As the rate of leakoff approaches the injection rate, the growth of the main fracture will cease and the actual penetration will be less than what would ordinarily be predicted by current mathematical models. In addition, because of the rapid leakoff of fluid and because few of the secondary fractures are likely to be wide enough to readily accept 20/40 mesh sand, sand concentrations in the main fracture are likely to become excessively high, leading to screenout conditions.[7] By using 100 mesh sand to pack these secondary fractures, creating an artificial matrix, the rate of leakoff can be reduced considerably. By utilizing this principal in the Mini Massive Frac technique, it is not possible to stimulate low porosity, low permeability formations using sand concentrations as high as 9 PPG in areas that have, historically, been confined to 1.5 to 3 PPG maximum sand concentrations.

Miller and Warembourg also pointed out that the 100 mesh sand would act to prop the secondary fractures after completion of the stimulation treatment.[5] These propped fractures would provide conductive channels into the main fracture, effectively increasing the drainage area. In addition, the 100 mesh sand remaining in the main fracture would be more easily suspended than the 20/40 or 10/20 mesh sands, due to its much greater surface area, and would tend to prop the extremities of the fracture, maintaining conductivity in areas of the fracture that might not ordinarily contain proppant. If indeed these principals are valid, we would expect to see not only increased production, due to increased drainage area, but also much slower declines in production in the post stimulation period, due to the fracture extremities being propped. This is, in fact, what the Mini Massive results indicate. By using large volumes of 100 mesh sand, production results are improved and sustained for longer periods of time.

The use of highly viscous crosslinked fluids is an important feature of the Mini Massive frac. Novotny has pointed out that only that portion of the reservoir adjacent to the propped fracture will be effectively stimulated.[6] In the post stimulation period, the unpropped areas of the fracture will be free to heal, under closure stress, and will provide little if any drainage capabilities. By using crosslinked PSD fluids, the proppant and excess 100 mesh sand will remain in suspension long enough after pressure is released for the fracture to close, trapping the proppant in place, Thus it is possible to obtain a more nearly even distribution of proppant throughout the fracture, providing for a greater propped fracture height and deeper penetration of the proppant than could be obtained by a less viscous medium. This increase in propped fracture height and propped fracture length is reflected in the improved and sustained production results obtained by the Mini Massive frac technique.

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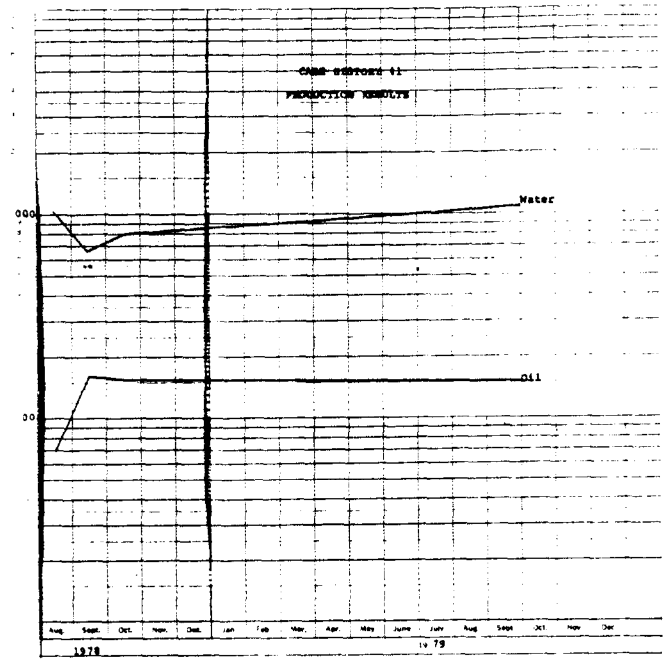
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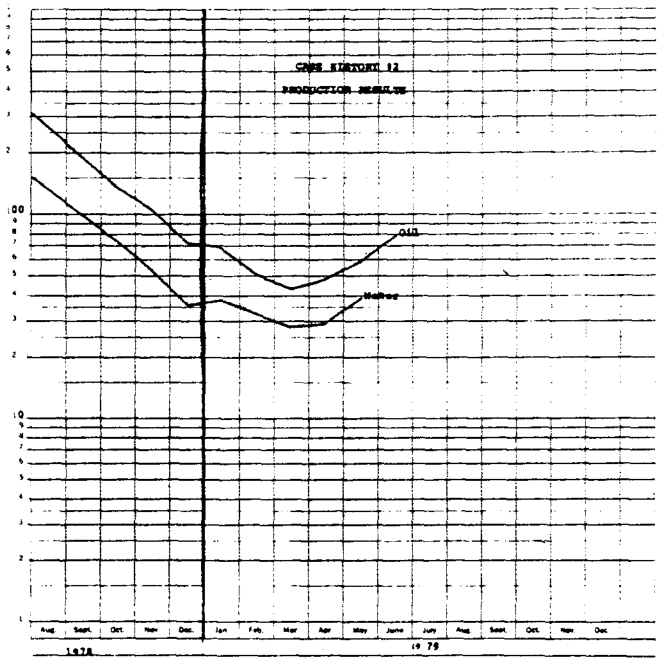
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