

HYDRAULIC FRACTURING: RECENT ADVANCES IN TECHNOLOGY DOUBLED SUCCESS RATE IN AUSTRIA

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ABSTRACT

The increase in success rate of hydraulic fracturing treatments during the last two decades is mainly based on the development of new fracture models. Convection, tortuosity and multiple fractures were identified as the most dominant issues. The new models dramatically changed design and execution of fracturing treatments. The optimization of treatments is only possible by onsite real-time data analysis. The success rate was further increased by the development of more effective stimulation fluids and proppants and the steadily increasing level of automation.

Proppant drops out of the pay-zone in vertically uncontained fractures because of downward convection of the proppant-laden stages. Convection can be reduced by decreasing fluid volumes and by increasing proppant concentrations and mass of proppant. Screen-outs in the near-wellbore region are caused by tortuosity and multiple fractures when injecting high proppant concentrations. These near-wellbore problems must be reduced to be able to avoid convection. The injection of proppant slugs is an effective method to reduce tortuosity and multiple fractures.

Since 1998 eight out of ten oil wells have been successfully fracture stimulated in Austria. The success rate was almost doubled compared to the 127 treatments executed between 1957 and 1985. The estimated ultimate economic recovery was increased by 65 percent. To date, the internal rate-of-return of the treatments is more than 100 percent.

INTRODUCTION

Hydraulic fracturing treatments have been used to

improve the productivity of oil and gas wells since 1947. Wells are fracture stimulated to increase the recovery factor in low permeability reservoirs and to bypass the damaged zone around the wellbore in high permeability reservoirs. In recent years fracture stimulations are also used to control sand production and to economically develop marginal oil and gas fields. In total, more than a million treatments have been executed and between US\$2 billion and US\$3 billion is spent annually to fracture more than 20,000 wells worldwide [1].

The development of fracture models started in 1955 [2]. But until around 1980 significant advances could not be made because these models were developed without accounting for real data. However, the fast evolution in computer technology allowed accurate acquisition and analysis of a huge amount of stimulation data which enabled the development of new models [3-7].

FRACTURE MODELS

At least five dominant issues have been identified to be critical for the success of hydraulic fracturing treatments.

The net pressure in a fracture is higher than predicted by the old models [2]. Higher net pressures are not only caused by non-linear elastic behavior at the perimetric fracture tip (dilatancy), but also by multiple fractures. Thus, the role of stress barriers is reduced and fractures are usually not contained in the pay zone [3]. Fracture growth is more likely to be vertical than horizontal and the maximum achievable fracture half length is of the order of 100 m. Furthermore, higher net pressures also result in wider fractures. In vertically uncontained fractures proppant transport is dominated by convection [3]. The heavier (proppantladen) fluid stages move downward to the bottom of a fracture due to gravity forces (Fig. 1). Thus, the proppant can drop out of the pay zone and can even fail to form a connection back to perforations from which the fracture emanated. The lower the permeability the more dominant is convection [4].

The stresses in the wellbore vicinity are different from the far-field stresses due to drilling and completing, i.e. perforating [5]. A fracture emanating from a perforation turns into the direction of the maximum horizontal stress at a distinct distance from the wellbore (Fig. 2). This curvature of the pathway is called tortuosity. Such reorientation leaves a segment near the wellbore which is not (mechanically) supported by the main body of the fracture. Hence, this segment will generally have less opening and may often close completely when injection is stopped, similar to a valve. In addition, fractures can emanate from each perforation. These multiple fractures compete for opening space in the near-wellbore region. Therefore, the multiple fractures will also have less opening. The smaller width in the wellbore vicinity causes screen-outs when injecting higher proppant concentrations.

The rheology of fracturing fluids and the injection rate do not significantly influence the width of a fracture [6]. Probably only water or slightly viscosified fluid reaches the very near-perimeter regions of the fracture in which the dominant component of the net pressure drop occurs [3]. However, rheology and rate do have an influence on the near-wellbore fracture pattern. More viscous fluids and higher rates tend to produce less and wider near-wellbore fractures [5].

Permeability variation plays a dominant role in the growth of a fracture [7]. Fractures preferentially propagate in impermeable (low leak-off) rock. Thus, high permeability layers can act as barriers to fracture growth, in contrast to high stress layers. Permeability barriers may play a favorable or unfavorable role. Fractures may tend to stay out of bottom water, but it may be difficult to drive a fracture into high permeability pay-zones, e.g. in multi-zone fracturing.

DESIGN AND EXECUTION OF TREATMENTS

The new models dramatically changed design and execution of fracturing treatments. The design of treatments is usually based on assumptions only. These assumptions are generally justified by e.g. well test analysis or special core analysis. However, the response of the reservoir to the propagation of a fracture can be measured only during and after injection of fracturing fluids. Hence, a fracture treatment can only be optimized on-site [4].

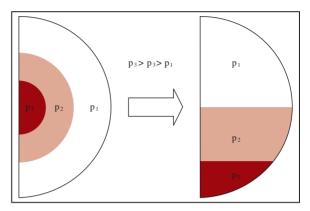


Fig. 1. Schematic representation of convection

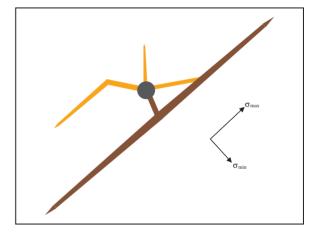


Fig. 2. Schematic representation of tortuosity and multiple fractures

Convection can only be reduced by decreasing fluid volumes and simultaneously increasing proppant concentrations and total amount of proppant pumped [4]. However, tortuosity and multiple fractures make the injection of high proppant concentrations of such aggressive designs difficult or even impossible. Thus, the near-wellbore problems have to be removed at first to be able to reduce convection.

Near-wellbore problems can not be predicted but can be measured easily [4]. The injection pressure jumps up when the rate is stepped up, or when high viscous fluids or small proppant slugs are injected into the nearwellbore region. The amount of the sudden pressure increase can be directly related to the severity of the near-wellbore problems.

The injection of small proppant slugs is also an effective method to remove near-wellbore problems [5]. The fracture pattern in the wellbore vicinity is simplified and the degree of tortuosity and the number of multiple fractures are reduced. If necessary, the well must be shut in on the proppant slug. If very severe near-wellbore problems are encountered, additional (bigger) proppant slugs must be injected.

Proppant slugs also allow the determination of far-field reservoir parameters [5]. A conductive pathway between the well and the reservoir is created by shutting in the well on proppant. The measured pressure fall-off can be directly related to the reservoir parameters beyond the wellbore vicinity.

The stimulation program should be designed as flexible as possible to be able to adapt to the encountered conditions. Besides the mainfrac to improve productivity, several tests, i.e. breakdown-stepdown test and minifrac, should be included into the stimulation program. In general, injection pressures pump rates, and proppant concentrations are acquired. These data are analyzed with PC-based software packages on-site (real-time analysis). The subsequent pump schedules can then be re-designed and optimized depending on the encountered conditions. Usually, additional proppant slugs must be injected, fluid volumes, mass of proppant, or proppant concentrations must be changed.

OTHER TECHNOLOGICAL ADVANCES

The success rate of fracturing treatments was further increased by the development of more effective stimulation fluids and proppants and the steadily increasing level of automation [1, 2, and 8].

Stimulation fluids with lower polymer concentrations were developed which have the same or even better rheological properties. Thus, the permeability impairment of the proppant pack by polymers was significantly reduced. Polymer-free fluids are already available for distinct applications causing practically no damage to the proppant pack [1].

Man-made proppants, i.e. ceramic products, have a higher permeability than natural frac sand due to a higher degree of roundness and sphericity [2]. These new proppants also resist higher rock stresses. Thus, less permeability impairment of the proppant pack is caused by crushing of particles which also allows fracture stimulation of deeper reservoirs. The level of automation increased continuously in the last 20 years. The main components of the fracturing equipment, i.e. pumps and blender, are operated by remote control [8]. The most important parameters, i.e. injection pressure, pump rate and slurry density, are acquired electronically. The increasing level of automation allows reacting quickly to unexpected situations.

TREATMENTS IN AUSTRIA

In Austria 127 fracturing treatments were executed between 1957 and 1985 (Fig. 3). Most of the stimulated wells were oil wells. The success rate of these 127 stimulations was only 43 percent and an extremely high failure rate was experienced in the 1980's.

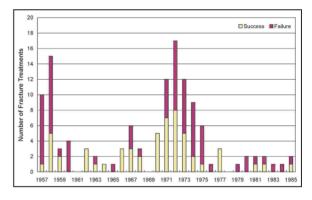


Fig. 3. Treatments in Austria between 1957 and 1985

However, due to the reported advances in technology and increased success rates, two fracture treatments were executed in 1998.

The production profile of one of the two successful stimulations is shown in Fig. 4. The oil rate before the treatment was approximately 4 m3/d. The expected production decline was about 10 percent per year. After the stimulation the well produced around 16 m3/d. The fluctuations of the production rate were caused by trying to optimize the intermittent gas lift system. The cumulative production increase is approximately 160 percent.

Encouraged by the success of the two treatments, another eight wells were fracture stimulated. All stimulated wells produced from oil reservoirs with low to moderate permeability. Solution gas drive was the main driving mechanism of these sandstone reservoirs. The depth of the reservoirs varied between 1,500 m and 2,800 m. Most of the wells were vertical, but also deviated wells and one horizontal well were fracture stimulated. In many cases, near-by water was the main reason for pumping relatively small treatments (Tab. 1). Fracture growth into the water-bearing layers should have been avoided in any case.

Convection was assumed to be a major problem due to the relatively low permeability of the reservoirs. By using aggressive pump schedules, convection should be reduced. In Tab. 2 the fluid volumes and proppant masses of a conventional treatment (1985) and an aggressive treatment (1999) are compared. The proppant mass of both treatments is approximately the same. However, on the one hand, the fluid volumes of the aggressive schedule have been decreased tremendously and on the other hand, the proppant concentrations have been increased significantly. The overall proppant concentration (total proppant mass in relation to total fluid volume) of the aggressive schedule is four times higher.

In many cases severe near-wellbore problems were encountered. A stimulation program including three tests before the mainfrac proved to be very successful to remove near-wellbore problems.

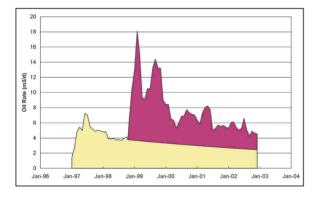


Fig. 4. Production increase of example well

Tab. 1. Size of treatments in Austria since 1998

	Fluid volume (m3)	Proppant (1,000 kg)
Smallest mainfrac	31	13
Average mainfrac	45	20
Biggest mainfrac	189	164
Tests before mainfrac	70	10

Tab. 2. Comparison of conventional and aggressive design

	Conventional	Aggressive
Proppant (1,000 kg)	63	56
Pre-pad volume (m3)	55	0
Pad volume (m3)	100	9
Carrier volume (m3)	195	57
Max. prop. conc. (kg/m3)	600	1,200
Overall prop. conc. (kg/m3)	180	850
Number of tests	0	3

After a breakdown-stepdown test a minifrac is pumped with about 2,000 kg of frac sand using concentrations up to 360 kg/m3. With the third test, up to 10,000 kg of sand are injected into the formation using concentrations up to 720 kg/m3.

Eight out of ten oil wells have been successfully fracture stimulated since 1998. The success rate was almost doubled compared to the treatments executed before 1985. The estimated ultimate economic recovery was increased by 65 percent. To date, the internal rate-ofreturn of the stimulations is more than 100 percent.

CONCLUSIONS

The increase in success rate of hydraulic fracturing treatments during the last two decades is mainly based on the development of new fracture models. Convection, tortuosity and multiple fractures were identified as the most dominant issues.

The new models dramatically changed design and execution of fracturing treatments. The optimization of treatments is only possible by on-site real-time data analysis. Pumping aggressive treatment schedules is the only way to reduce convection. Proppant slugs proved to be successful in removing near-wellbore problems.

The success rate was further increased by the development of more effective fracturing fluids and proppants and by the steadily increasing level of automation. The new fluids and proppants result in reduced permeability impairment of the proppant pack. The increasing level of automation allows reacting quickly to unexpected situations.

By implementing these new technologies, eight out of ten oil wells have been successfully fracture stimulated in Austria since 1998. The success rate was almost doubled.

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Bernhard Schlager hold MS degree in Petroleum Engineering from University of Leoben, Austria. He started his career as Petroleum Engineer in OMV Exploration & Production, Austria in 1998. His main



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