# Getting it right the first time

Kevin Fisher, Flotek Industries, USA, explains how in the field of hydraulic fracturing, **there are no second chances when it comes to getting fracs right.**

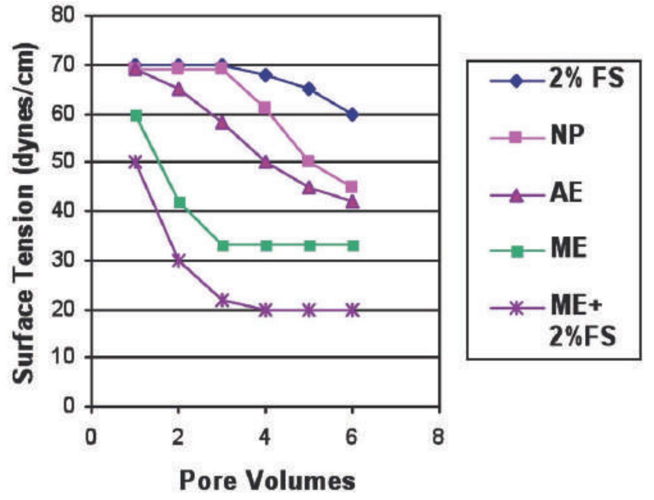


***Figure 1.*** *Measured reduction in surface tension using several conventional surfactants.*

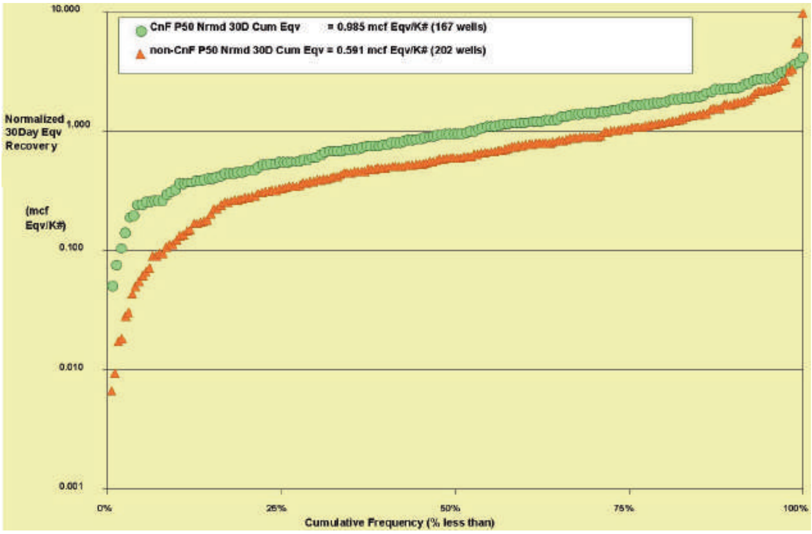


***Figure 2.*** *A comparison of results compiled by Dr Jim Crafton of Performance Sciences, Inc. on several hundred wells in different environments pumped with and without CnF products.*

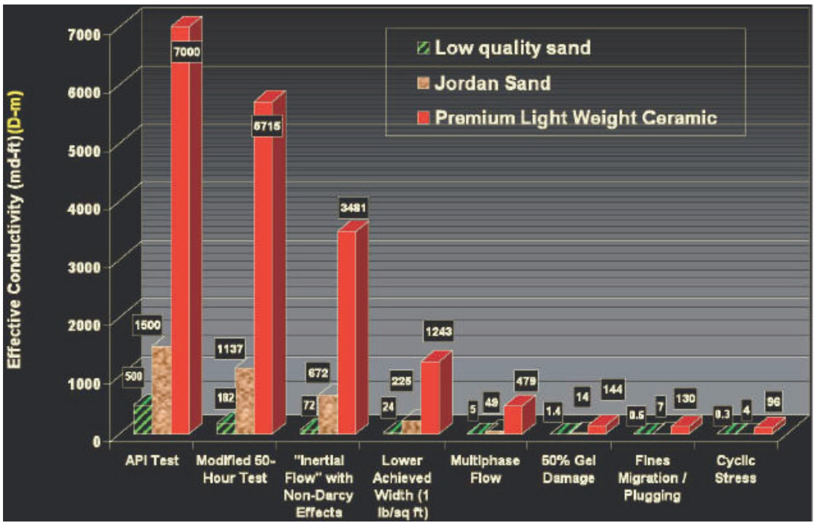


***Figure 3.*** *The standard API laboratory 'baseline' conductivity tests for low quality 'brown' sand, high quality 'white' sand and ceramic proppant. Courtesy of Mike Vincent[1].*

Everyone has been directed at one time or another to 'do it right the first time'. Sometimes, there are processes that are flexible and forgiving enough to allow for later corrections that allow this command to be broken, but often, it absolutely must be done right the first time. Brain surgery and hydraulic fracturing of horizontal wells are two instances where you simply have to do it right the first time.

The earliest applications of hydraulic fracturing technology were not met with fanfare or headlines. History, however, is changing, because it is now clearly understood that the oil and gas industry in the Western Hemisphere has not been the same since the first fracturing treatments pumped in 1949.

By 2013, hydraulic fracturing has allowed commercial hydrocarbon recovery from more than 1 million wells that would never have produced economically, if at all. Moreover, it was hydraulic fracturing that ushered in the age of unconventional resource plays. Eventually, Barnett operators combined multistage hydraulic fracturing methods with horizontal drilling, and the ultra-low perm Barnett suddenly became a prolific gas producer. Gas shale and tight oil resource play development took off all across North America, opening a vast new base of economic oil and gas resources.

Natural gas is an abundant fossil fuel and with modern extraction methods such as horizontal drilling and multistage hydraulic fracturing. It is now recoverable in volumes that will carry the globe forward for a century or more into the future with abundant, low cost and clean energy. This cheap energy is the best way to boost global economic growth. In a sense, the world could be entering a new period of global economic expansion with a fuel that is friendlier to the environment than coal and conventional liquid petroleum.

A hydraulic fracturing treatment increases the contact area with the reservoir, which accelerates oil and gas production so that a well can produce more in a few months or years than it would have produced in decades, or in the case of ultra-low permeability shales, centuries. Nearly every natural gas well in the US, and by some estimates, more than 60% of all US oil wells, are hydraulically fractured today. Most of these wells could never be drilled or produced profitably without the application of hydraulic fracturing.

## No second chances

Because of the mechanics of fracturing a horizontal wellbore (the drilling method of choice in unconventional reservoirs so that more reservoir rock can be contacted by a single wellbore), it is imperative that the optimum fracturing treatment be performed the first time because it is nearly impossible to go back and remediate any mistakes once the well has been cased, perforated and the primary fracture treatments performed. The problem is one of how to focus multiple frac treatments into a wellbore that now has hundreds or even thousands of holes perforated in it and where the subsequent refrac treatments are difficult, if not impossible to focus into one small interval at a time without attendant mechanical risks of damaging the wellbore.

Non-optimal fracturing treatments can still produce hydrocarbons, and in some instances, abundantly so. But whatever the ultimate recovery from a non-optimally stimulated wellbore, by definition that produced hydrocarbon volume will be less than optimal. Royalty owners will ultimately receive less revenue, taxing authorities and therefore the public will be shorted and importantly, the operator of the well will have less production, lower profits and reduced net present value, reducing the return to their shareholders.

## Making the right choice

Today, in the low permeability resource plays, a number of fracturing designs are employed from viscous gel frac treatments designed to carry large concentrations and volumes of proppants to obtain the most conductive fracture possible, to thin fluids (or waterfracs) designed to be able to reactivate the natural fractures that allow shales and ultra low permeability plays to be commercially productive. Thin fluid 'waterfracs' do not carry as much proppant as viscous fluid systems but have the advantage of being able to 'finger' into natural fractures and reopen them during the treatments and can carry just enough proppant to allow for enough fracture width to be productive while at the same time being a very clean fluid system that has no solids or polymers which must be broken and removed so that the formation face and the propped fracture itself are not damaged or plugged by the gels. Typically, the viscous fluid systems with larger amounts of proppants are used in the highest quality/most productive reservoirs and more frequently with oil wells while the thin fluids are generally used at the lower range of permeability in natural gas wells and in some low permeability oil reservoirs. The chemical packages for viscous frac fluid systems and water frac systems have some components in common, but in general are quite different from one another.

Outside of North America, the majority of fracs pumped in conventional formations utilise viscous linear or cross-linked gel systems. Within North America, low-permeability gas reservoirs, particularly shale gas, are almost universally stimulated with water fracs. Typically, 10 – 40% of the fracturing fluid pumped into a wellbore is recovered post-frac and must be handled for disposal or reuse.

## Frac chemistry

Typical fracturing additives consisted of various gelling agents, biocides, surfactants, scale-inhibiting agents along with crosslinkers and gel breaking additives (in the case of gel systems).

It has been recognised that some of the chemicals being used, while effective in boosting productivity and well longevity, could be hazardous, particularly in concentrated form. A movement began more than a decade ago to produce greener additives to replace diesel, fluorocarbons, benzene, toluene, ethylbenzene and xylenes (BTEX) and other bad actors – an effort that is still underway. Several chemical scoring methods have been developed to determine the relative toxicity of various chemical compositions, and international standards such as REACH, GreenCheck and others have been established and are still evolving. Chemical reporting organisations such as FracFocus in the US now require producers to disclose the chemicals being pumped on a well to the public and regulatory bodies, while still preserving some of the proprietary fluid constituents that differentiate one provider's chemicals from another.

Nearly every new chemical product being developed today is created with the idea in mind to be greener and more effective than the product it is replacing. It is not always easy (or cheap) to design for greener or more effective products, making chemical research and development an area where much time and effort is being spent by service companies and chemical providers alike. One of the most promising new areas of research is in employing nanoparticles as carrying agents, or 'smart bots,' to ferry various chemical agents into and out of the reservoir. Their small size allows for better mobility through the fracture and into the reservoir, which can aid in fracture fluid flow back, formation damage mitigation, improved hydrocarbon mobility, etc.

Just as with new nano-proppants being developed, chemical nanoresearch shows great promise in improving hydraulic fracturing's effectiveness and is already improving fracturing's environmental impact and productivity in many basins. Sustainable, green chemicals such as citrus oils are now used in conjunction with nanofluids to get better production with less environmental impact. Many chemicals now under development are targeted to be biodegradable, leaving little to no bioaccumulation.

Biocide research and development is also rapidly replacing some of the most worrisome chemicals traditionally used in the frac job. By their very nature, biocides can be harmful. The move is to design-in biospecificity, so that the biocides target only the microbes in water and only for a short time so that there is no cumulative effect on fish, wildlife and humans. These bacteria can create sour gas and have a negative effect on gel systems, so they must be controlled. Other novel ideas are being employed such as using ultraviolet light to kill bacteria and chlorine dioxide generators and ozone to purify frac or injection water using a similar system to what is used to treat municipal drinking water.

## Dividing opinion

In 2003, long before the current media scrutiny and environmental activism surrounding hydraulic fracturing surfaced, Flotek Industries chemical group, CESI, applied for a patent on a 'green' fracture stimulation surfactant, "Complex Nano Fluid™" or "CnF® Additives." That product, built on a citrus (food-grade orange oil termed d-limonene) base, is biodegradable, natural, renewable, and sustainable, it carries a friendly environmental scorecard and can improve post frac well productivity. The surfactant is approved for stringent North Sea regulations for all EcoTox categories including biodegradable, bioaccumulation and aquatic toxicity to fish, crustaceans and algae. This product contains no Priority Pollutants under the US Clean Water Act, there are no known or suspected carcinogens, halogens, ozone depleting chemicals, petroleum or BTEX products.

Most of the waterfracs pumped today utilise very few chemicals, typically a biocide, a friction reducer and a surfactant, plus water and proppant and sometimes a scale inhibitor. By volume, the CnF fluid's concentration is typically very small (0.2%). Other additives such as biocides and friction reducers are often included in even smaller concentrations. In an ideal world, an operator would recover substantially all of the fluid pumped during the treatment so as not to leave the water behind in either the formation or in the created fracture itself. High water saturation at the fracture face and within the propped fracture significantly impairs hydrocarbon flow into and through the propped fracture. Most wells stimulated in unconventional/shale formations recover less than one-half of the original fracture water volume (frac loadwater recovery is typically 10 - 25% in ultra-low permeability reservoirs). The unrecovered frac fluid remains trapped in the fractures and in the immediate region of the formation surrounding the fractures and has several detrimental effects including reduction of the relative permeability to hydrocarbons, a smaller effective flow area and less effective fracture length, all leading to lower well productivity.

The additive's chemistry reduces surface tension and interfacial tension between the rock and injected fluids. The water is held in place by capillary forces which must be overcome in order for the gas or oil to enter and flow through the pack and this is what the additive does – it reduces capillary pressure, allowing more fracturing fluids to be recovered at lower pressures in an efficient piston-like

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manner, which then allows better hydrocarbon entry into and through the fractures. CnF minimises capillary end effects associated with wellbores and fractures in low permeability reservoirs by about 50%. In other words, it makes 'slickwater' even slicker and can remediate formation damage. Due to this more efficient dewatering, the additive is also effective in depleted or under pressured gas wells. Additionally, the grains in tighter proppant packs have a stronger attraction to fluid, resulting in higher pressures necessary to dewater the pack; so with today's tendency toward smaller proppants in many ultra-low perm gas wells, the additive can improve production when using small proppants. Additionally, it can minimise fluid adsorption on shales and fluid leak off into the formation, both of which can be significant formation damage factors.

## Comparisons

Figure 1 shows the measured reduction in surface tension using several conventional surfactants. The worst performing conventional surfactant in this test (blue symbols at top with least reduction in surface tension) can be contrasted with the best performing additive (the purple symbols at bottom showing the greatest reduction in surface tension). This is the same surfactant with the only difference being that the best performing version is that surfactant embedded in a complex nano fluid. This means that fluids will flow through the rock and through the fracture at lower drawdown pressures. In other words, more fluid flows from the reservoir at a given pressure drawdown. This means that more fracturing load water is recovered and more hydrocarbons will be recovered.

The fluid's increased water recovery (lower water saturation inside and near the fractures) means higher relative permeability within the fracture which leads to longer effective fracture lengths for a given fracture volume. More frac fluids can be recovered between stages or between wells, helping reduce costs associated with transporting additional fluids to job sites. Well cleanup time is faster, and less 'makeup' water needs to be added to pits and frac tanks in order to have sufficient fluid on hand to perform the fracturing services. Additionally, effective fracture length deterioration due to shut-in periods is less than half that of other treatments.

Improved production results from the use of these additives have been published for many conventional and unconventional reservoirs and basins including the Granite Wash, Barnett Shale, Signal Peak, Fayetteville Shale, Appalachian Basin sands and shales including the Marcellus and Utica Shales, low-perm sandstones in the Piceance and Uinta Basins, the Vicksburg of south Texas and the Cotton Valley of east Texas, the Codell and Niobrara of the DJ Basin, Green River Basin, and the Jonah and Pinedale anticlines in the Rocky Mountains and many others. Since the original development, more than 10 000 wells in over 20 basins on six continents have benefitted from this nanotechnology.

The graph in Figure 2 is the summation of all the public data sets in the five studies that Dr. Crafton has thus far completed. No forecasting is involved; this is the actual 30 day production on these 369 wells. The cumulative frequency histogram shows the performance in terms of the gas equivalent is normalised for reservoir quality, pressure drawdown and treatment size. The 30 day equivalent recoveries are divided by the treatment size in terms of thousands of pounds of proppant placed. As can be seen, the observed, normalised 30 day performance of the CnF product family wells was approximately 60% better than those equivalent neighbouring wells with 'traditional' surfactants. This population includes wells from the DJ Niobrara, Green River Lance and Marcellus, including horizontal and vertical wells, gas condensate and oil wells, water and gel fracs, with more than a dozen operators and pumping service companies. Better fluid technology makes better wells.

## Fracturing proppants

Fracturing chemicals together with proppants probably have the largest effect on how a given fracture treatment performs, assuming it is of the proper size and is placed within the pay zone. Proppants are materials that are used to hold the fracture open once the pressurised fluids create that fracture. The ability of that propped fracture to enhance fluid and gas movement out of the reservoir and back into the wellbore is key to the hydrocarbon deliverability of a well. Large surface areas from fracture networks obtain the necessary contact area with the reservoir and proppants are the mechanism that ensures that a portion of that large surface area remains connected to the wellbore.

The global proppant market is likely to be more than 40 billion lbs of proppant consisting of everything from brown sand to white sand, lightweight to intermediate and heavyweight ceramics, and with almost all of these products available with cured or curable resin coatings. Resin coatings are used to strengthen the proppant grains and also to help confine any proppant that crushes so that the created fines are trapped within the resin coating. Resin coating also increases the grain-to-grain friction so that proppant is not as easily unseated during production. The trend in proppant sizing in unconventional gas wells had been toward smaller proppants in the hope that more of the proppant could be placed farther into the reservoir. With the shift back towards oily reservoirs, the need for higher proppant conductivity to move liquids at high rates has caused a shift back towards larger proppant sizes. Originally, ceramic proppants were reserved for only the deepest, highest-pressure wells because of the need for their increased strength due to the cost differential with sand. As more data were gathered, the ceramics have become more prevalent even in shallower wells because of the uniformity and smoothness of the particles, which increases conductivity above and beyond natural sand grains.

Engineers typically design for a fracture conductivity sufficient to allow unimpeded flow rates of oil or gas expected from the well being fractured. Fracture conductivity is a function of the quality of the proppant, the size of the proppant and the concentration of the proppant pumped in a given reservoir. Laboratory data on proppant conductivity is available for nearly all proppants and under varying conditions of formation stress, temperature, etc. So from a design perspective, coming up with just enough proppant conductivity would seem to be optimum because more conductivity costs more money. Factors related to flowing characteristics and proppant pack damage factors increase the amount of conductivity one needs to purchase with that frac job.

As can be seen in the baseline API data in Figure 3, the high quality sand has about three times the conductivity of the brown sand and the ceramic proppant has almost five times the quality of the high quality sand. So if one were only designing for a reservoir, which required modest deliverability, 500 or 1500 ft of conductivity may be more than enough to ensure that the deliverability of that reservoir is not restricted. But as can be seen from the Figure, there are a number of other factors, which degrade that baseline conductivity including non-Darcy effects, multiphase flow and other damage factors. Realistic in-situ conductivities could be reduced by 90% or more depending on actual reservoir and flowing conditions. So what looks adequate in lab baseline conductivity tests may in actuality be under-designed from a proppant quality standpoint.

## Conclusion

As can be seen, hydraulic fracturing is a complex process, which means optimisation requires solid engineering skills applied to a rich data set upon which numerous critical technologies are modelled and then performed. This article has highlighted two critical components of a successful fracturing operation. Of course, many decisions are made prior to the stimulation operation on where to drill the well, how long the lateral is to be drilled, how many frac stages will be pumped, will the well be completed open hole, cemented, slotted sleeves, plug and perf, etc. All of these decisions also influence the ultimate productivity of the well, but once the well is drilled and completed and readied for stimulation, good chemistry and proppant selection are most crucial to the ultimate outcome. OT

## References

1. ST Sand: SPE 14133, 16415, CL: Carbo typical, LT: Stim-Lab PredK 2002, SPE 24008, 3298, 7573, 11634, CARBO Tech Rpt 99-062, Run #6542, StimLab July 2000, SPE 16912, 19091, 22850.