ProTechnics

Expert's Corner

INTERVIEWS AND DISCUSSIONS WITH INDUSTRY EXPERTS

DEEPWATER COMPLETION TECHNOLOGIES – FRAC PACKS ARE HERE TO STAY

Interview with Mike Mullen, Mullen Energy

Interviewed by Wade Hutchinson

Expert's Corner this month interviews Mike Mullen, Mullen Energy, on the latest methods and thinking in deepwater Gulf of Mexico (GOM) completions. Mullen Energy has provided completion consultation on many of the industry's most challenging GOM deepwater projects.

Q: ProTechnics
Your career over the last 16 years has placed you as one of the leading experts in offshore completions and operations. Mullen Energy, which you founded in 1996, has provided completion consultants to many of the top world class GOM Deepwater projects. It is this particular completion expertise I would like to explore. Would you start out this interview by defining the different types of completions currently being employed in the Gulf of Mexico?

A: Mike Mullen
There are four basic types of sand control completions being performed in the Gulf of Mexico: the horizontal gravel pack, high-rate water pack, gelled pack and the frac pack. The frac pack has emerged as the most common type of completion currently being used. Most companies employing the frac-pack treatment are doing so due to the lower average skin values and the long term sand control reliability record of this type of treatment. The high-rate water pack is still being used on completions where the risk of fracing into a water zone is deemed unacceptable. Water-packed horizontal completions are also being used in the Gulf of Mexico when the reservoir characteristics deem this type of completion as the optimal recovery option. The gelled pack is a seldom used technique where the sand is pumped at just below frac pressure.

Q: ProTechnics
As you stated in the previous question, frac pack completions have taken over as the most common completion technique used in the deepwater Gulf of Mexico. Please give our readers a brief history and evolution of the frac pack completion and where it is today.

A: Mike Mullen
The first two wells I am aware of to be fractured in the Gulf of Mexico were in the early 1980's. These treatments were designed and executed similarly to standard hard rock type fracturing theory and resulted in longer narrower fractures than the shorter wider fractures of today. These early treatments did not prove successful enough to be continued.

Initially the hardest part of frac packing was mentally overcoming the golden rule of gravel packing which was, do not exceed fracture pressure. Not to be deterred, BP and Pennzoil, in the late 1980's, pumped the first successful tip screen out (TSO) fracture above the fracture pressure. These early tip screen out treatments placed short and wide fractures. Further advancements by BP and Pennzoil forced equipment innovation and continued to extend the length and width of these fractures resulting in much higher sustained production rates than were typically seen in gravel packed wells. One by one other company's began attempting and adopting frac pack completions as the standard stimulation and sand control method in the Gulf of Mexico.

Early frac packs were pumped at 10 bpm with proppant concentrations up to 12 ppg placing total proppant volumes up to 40,000 lbs. Research and development by the service companies made significant advancements in the development of downhole crossover tools. These new generation tools were designed to handle the increased erosional forces caused by the increased pump rates, high proppant concentrations, high volume of proppant and the move to more abrasive ceramic proppant materials. Today we are routinely placing frac packs at 50 bpm, with 12 ppg proppant concentrations and total proppant volumes in excess of 200,000 lbs

The frac pack completion is here to stay. As deepwater wells continue to require higher production rates to meet economic hurdles, injection rates and proppant volumes will continue to increase.

Q: ProTechnics
What is the basic theory behind the frac pack completion and what role has this technology played in the deepwater development?

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Core Lab™ RESERVOIR OPTIMIZATION

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A: Mike Mullen

The frac-pack theory simply allows for the bypassing of near wellbore damage created during the drilling process, the perforating process, and fluid loss management procedures. The wide fractures also provide the reservoir with additional flow capacity that serves to provide stimulation to the reservoir. By bypassing the near wellbore damage and creating a stimulation effect for the completion, typical skin values of +10 to +60 for gravel pack completions have dramatically reduced to -4 to 15 for frac pack completions. These beneficial skin values associated with frac packs made the completions more efficient and produced at much higher flow rates at lower draw downs. Fifteen years ago wells making over 2,000 BOPD in the Gulf of Mexico were unheard of. Today many operators are planning completions where expectations over 20,000 BOPD are being met.

An equally important reason for the popularity of the frac pack in the Gulf of Mexico is the sand control reliability these completion types have exhibited over time. Companies are usually drawn to the frac pack treatment for the allure of the higher flow rates and lower draw downs experienced in these type of completions. But after a few years of producing their wells, operators are becoming more convinced that the reduced sand control failure rates are equally as important. This is especially true in subsea deepwater projects where well interventions are so costly that repairing screen failures can be prohibitive.

It is true that the frac pack treatment through its inherent sand control reliability and the stimulation effects with higher rates and lower draw down pressures have brought many deepwater projects into reality.

Q: ProTechnics

There are two screenout terms discussed in the industry as it relates to frac packing. The first is the tip screen out and the second is the wellbore screen out. Would you please describe these two terms for our readers?

A: Mike Mullen

The tip-screen-out (TSO) occurs when the sand or proppant reach the tip of the fracture and halt further fracture extension. Additional slurry injection into the fracture beyond this point simply balloons the fracture creating more fracture width and packs the fracture from the tip back towards the wellbore. Frac widths greater than one inch are obtainable with this type of treatment. Pressure response seen at the surface is typically a unit slope on the Nolte-Smith plot or net pressure plot when the tip screen out occurs

If every thing is designed correctly following the tip screen out, the wellbore screen-out event takes place. This happens when the sand or proppant has packed or bridged off near the wellbore and a screen out has occurred at the top of the screen section or above the perforated interval. At this point all leak off is stopped and pressure spikes at the surface until the pop-offs and emergency shut-downs stop the treatment.

There is much debate over the placement technique for the final wellbore screen-out. Some practitioners would like to slow the injection rate to 2 BPM and circulate in the final wellbore screen-out, while others would prefer to lock up the treatment at or near the initial injection rates. I prefer to lock up the treatment near the initial injection rates and then bleed off the trapped annulus pressure to fill-in any wellbore voids which may exist. This technique ensures the maximum obtainable fracture width is packed back to the wellbore and that possible annular voids are filled. The most productive wells I have seen employed this type of wellbore screen-out technique.

Q: ProTechnics

Completion diagnostics are being included in many offshore completions. What are the main types that you use and would you share your opinions on the value that each bring to the project?

A: Mike Mullen

The most common used completion diagnostics are real-time surface pressures on the work string and on the live annulus. In addition, memory-based washpipe pressure and temperature gauges, gravel pack gamma-gamma density logs, radioactive tracer logs and chemical tracer analysis are being routinely employed.

This diagnostic data is used more for post-treatment analysis, well completion review and forward project planning. The use of multiple bottomhole pressure and temperature gauges is becoming more common with the longer intervals being treated in today's deepwater environment.

This data can help determine when the completion fluid is making it to the bottom of the interval or to determine when a section of the completed interval stops taking fluid. When dealing with multiple lobe completion intervals of varying permeabilities, the use of multiple bottomhole gauges in combination with radioactive tracers can be very helpful in determining treatment effectiveness and coverage. Also gaining in popularity and usage are the gamma-gamma density logging tools which can add significant value in determining if voids exist in the wellbore pack. Chemical tracers in stacked pack completions have allowed company's to determine when specific completed intervals were contributing or more importantly when specific intervals were not contributing the flow stream.

Q: ProTechnics

We have spoken before about using washpipe pressure and temperature gauges to indicate what is going on in the casing screen annulus during the frac-pack operation. What are the benefits and limitations of pressure and temperature gauges in the washpipe?

A: Mike Mullen

Many times the washpipe pressure and temperature gauges are located inside the washpipe which allows one to see the bottomhole pressure conditions without the effects of friction (work string) or fluid loss/weeping devices in the cross over tool (annulus). Temperature inside the washpipe can be confusing at times and certainly has delaying effects due to heat transfer coefficients. Newly developed washpipe pressure and temperature gauge carriers not only allow the gauge to be protected inside the washpipe but allow for the pressure and temperature readings to be made between the washpipe and the screen. This new gauge measurement location has minimized the delay of the temperature response and has produced surprising results with pressure diagnostic capability.

When multiple gauges are run in long intervals with external reading gauges, differences in treating pressures at different intervals have been observed. Washpipe gauges provide the best diagnostic value to the completion when positioned such that the point of measurement is between the screen and washpipe, not the inside of the washpipe.

Q: ProTechnics

As longer gross intervals are being stimulated in single treatments, what importance would you place on being able determine in time reference what is happening in the casing screen annulus during the treatment?

A: Mike Mullen

As the intervals requiring frac packing increase in gross height, the injection rates necessary to ensure the entire interval is being treated are increasing accordingly. These higher injection rates introduce problems with friction pressures between the casing and screen which can divert flow into the upper portion of the zone of interest, causing inadequate stimulation in the lower regions of the zone. In extreme cases, rate-induced higher friction pressures can divert flow from the screen/casing annulus to the washpipe/screen annulus causing a condition that result in a premature wellbore screenout with the proppant bridging at the top of the screen. So in a deepwater project where several long intervals are going to be frac-packed, knowing where the various proppant stages are going at any point in time would help optimize future stimulation treatments as well as optimizing the length of interval which can be stimulated effectively. The time dimension can also play a vital role in recreating job playback for problem solving situations.

Q: ProTechnics

What is the current state of the art with regards to modeling frac pack treatments and where do you see the industry going with respect to correctly modeling these offshore reservoirs?

A: Mike Mullen

Considerable time and money has been spent by the industry to create fracturing models and simulators to simulate and predict rock fracturing behavior. Unfortunately, most of the time and money has been spent modeling hard rock behavior. The lower-end Young's Modulus rock behaviors experienced in deepwater reservoirs need more investigation and explanation. Experience has indicated that these low modulus rocks are not fracturing in the traditional sense of a crack being created and propagated in rocks with higher modulus values. Thus, the fracture heights modeled are not being developed in actual practice.

Q: ProTechnics

Do the fracture simulators that were designed for hard rock adequately work in offshore unconsolidated reservoirs?

A: Mike Mullen

In general I believe they work well but, there are improvements which could be made in today's fracturing simulators that would be beneficial. For example, the simulators on the market today model the fracture only. For the sand control or frac-packing environments, I would like to see the models more adequately take into account the wellbore geometry considerations of the frac-pack completions. These additional geometry considerations are with the screen, blank and packer flow paths which are present in the wellbore, and the shear on the gels in these environments. I would also like to see these simulators try and predict the type of annular pack efficiency which the treatment leaves in the wellbore.

I believe that models of the future will adequately address both the fundamental difference between soft sediment reservoirs and hard rock reservoirs and will be able to model the complexities of the screen and hardware condition as it pertains to the pack left in place.

Q: ProTechnics

There is a lot of interest and discussion in smart well completions. What do you see as the future of these completions and where will they have their biggest impact?

A: Mike Mullen

Subsea completions will be most affected by the smart well technologies, because intervention cost for re-completions can quickly run in excess of $10 million dollars (US). The ability to change producing intervals by a sequence of control line pressure ups and bleed-offs from the host platform will make any production profile or cash flow profile look much more inviting. Typically, saving one rig mob and de-mob will more than pay for the smart well equipment and the additional initial completion time and cost.

Other wells in the Gulf of Mexico have had smart well equipment installed but by far the easiest economical justifications will be in the subsea wells. I anticipate that the smart well completion is where some of the most exciting technology improvements for downhole flow and regulation will take place in the future.

Completion diagnostic services are part of a full range of Core Lab services for reservoir optimization. These services are provided through the following business units:

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This interview was previewed in the Spring 2005 / April issue of the ProTechnology newsletter. To download a complete version of this and other interviews, as well as other information on completion diagnostics, please visit our website at **www.corelab.com/protechnics**

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