The SPE-GCS Podcast "Unconventional Completions" Transcript
George King – 08/10/2021

Marty Stetzer: Hi everyone, and welcome. I'm Marty Stetzer, President of EKT Interactive in Houston. We're proud to be the podcast sponsor with the Society of Petroleum Engineers, Gulf Coast Section. The section was founded in 1935 and now has over 11,000 members. It is a volunteer organization that provides member forums to upgrade and maintain professional competency. This podcast is one of a series and another learning resource available to the members. Numerous on-demand webinars can be accessed at www.spegcs.org.

Today, our topic is "Reducing casing damage during fracturing – the causes, warning flags, and ideas for control." And I'll be speaking with Mr. George King, with over 40 years in the upstream industry. We're really happy to have his input on this topic at this time of unprecedented challenges in our industry, especially those that affect the future of the important shale plays in the US.

George, thanks so much for taking the time today.

George King: Thanks, Marty. Very good to be here.

Marty Stetzer: George, before we get started, I saw on LinkedIn that while you were at Apache, you became involved with a group, New Completions and Stimulations Technologies. Can you expand on what was going on in those days, and other parts of your career, related to today's topic?

George King: Certainly can. Actually, I pursued the completions and the stimulations issue here for about 50 years… in each of the companies that I have worked for including Amoco, BP, and Apache.

And since 2018, I've worked as a consultant to the industry, via Viking Engineering, and as an SPE volunteer on workshops and specific summits or forums. My intent here is to try to get new technologies and older technologies that really work well, to focus on completions and stimulations in the most effective manner possible.

Marty Stetzer: George, that's great. With that background, let's get into the topic. What are the primary reasons for casing deformation or damage during fracturing?

George King: Okay. This information is the result of cooperation between a group of engineers and geomechanics, scientists working this issue, and they've been sharing some of their learnings and experiences.

Oftentimes, we talk about the failures, which we don't often talk about in SPE, and in this group here, that we don't quote people or companies or anything else… we're able to see some of these things, why it's caused, how it's caused. So we'll cover a few of them here.

We've discussed in this group over two dozen direct or indirect causes of casing damage and found that the identity of a specific damage appears to change from basin to basin. We worked and heard of damage in probably six or seven different active basins right now. So I'm going to cover a few of these causes just very briefly here as we go through.

The casing damage causes that, and we rank these for risk, and the ones that are within the top 10 usually include one or more of the following: Either faults or bedding planes that are activated and slip under the fracturing pressure. Some highly variable stress states including very local stress increases as the fractures start to grow and you're dealing with the pressures of fracturing and also with the proppant transfers into these rocks, you're pushing out, you're having a lot of stress changes.

The well path and orientation are also very important depending on where you want that fracture to go. Will it be longitudinal or transverse to the wellbore itself?

Now, the well design and particularly the coupling design and casing weight – and here is where we reached an agreement here – that use the casing diameter over the thickness ratio, and that should be less than about 12. And we've seen that increasing the casing thickness is more effective than increasing the casing grade or strength. This is a learning that we've gone through.

Also, perforation, cluster location, and spacing. Many companies are putting these extremely close together and we feel that that's part of the problem in some of these wells.

Fracture treatment design, the volume, the rates, the ramp-up, the stage numbers, and you've particularly got to watch the cyclic application of stresses, which is common to all of our multiple fracture stimulations in these horizontal wells – because that can lead to fatigue in both the casing and the cement.

Fracture-driven interaction, or frac hits, is a big part of this. And if you're in an area with long planar fractures, and you're thinking about putting these wells closer and closer together, you really need to look at the potential for frac hits.

A big one here on the mechanical side is undetected dogleg severities. I know that most of the drillers report 7 to maybe 10 degree doglegs, but these are averaged over an entire stand of drill pipe often exceeding 90 feet between the measurements. And so, that pipe, especially under directional drilling factors, can increase the inclination or the azimuth changes to a point where you get doglegs of over 20 degrees really quickly here, and that can really cause some non-continuous or nonlinear loading on these casings.

We also see thermal changes to the formation and/or the casing here… when you use cold frac water, putting that down into a hot formation that's come to equilibrium with the casing… and that casing axially will try to contract… which any contraction on a casing is going to reduce the collapse resistance of the pipe itself.

Also, just as another one here, the geomechanical factors and geology factors such as high permeability channels, barriers, variances in the rock fabric, or differences in the near and far field stresses are going to be a very big factor. So these are the kind of ones that usually rise into the top 10.

Marty Stetzer: George, can you also introduce the complexity of completions in a shale play, especially with laterals that are over two miles with over 50 or more fractures common today?

George King: Well, in this industry that we work with, this upstream industry, we're dealing with formations here that were deposited a few millimeters at a time, over the course of maybe a couple of million years. And the depositional points here, the depositional conditions change quite a bit.

And what we see here is there's a lot of variance just in that depositional change and the formation can take on higher permeabilities, higher stresses. There's a lot of things that happen here.

Also, when the well is turned to penetrate the formation in a near horizontal manner, these changes in composition or stresses along the link will produce conditions that will be a transverse fracture in one area, or a linear or longitudinal fracture along the wellbore in another area.

And this is compounded by putting these fractures close together, because the shadowing effects and the stress interference effects at the wellbore and far field, can give us a totally different performance along the well out of a single casing design.

So that gives you an idea here about what's going on, but added to that is that most of our fracture designs are based on stress assumption with average permeabilities. It may be... and the design may be perfect in one area and be totally wrong for an area maybe 200 yards or 200 meters down the wellbore. So we push grouping of like-formation characteristics and that seems to have some benefit over the average input of a single frac approach.

Marty Stetzer: George, with that background… When during the frac and where along the lateral is damage likely to occur, and most importantly, why?

George King: And this gets back into the who, what, why, where questions that we have to ask, but the **when** is controlled by areas where damage-inducing conditions are the highest. In other words, we've done a risk analysis and we see that this is an area that in our study wells has had casing deformations.

And typically those show up during, or right after the fracturing application. The highest areas of risk are thought to be triggered by the application of the fracturing pressure, the changes in temperature, and even this fracture growth that changes the stresses in their areas.

Now, one interesting point in the **when** dialogue is that casing deformation is typically seen during the fracture. And what happens here is you're pumping these fracture plugs down in a "perf and plug" type completion. You're pumping this plug down; you're setting the plug, pulling off, perforating several perforation clusters and coming out of the hole.

But in many cases, you'll fracture two or three toe stages and then you can't get the next plug down to within 1,000 feet of where you were fracturing before. And this is where we see this highly variable area. And there's points that we can do, to look at why this might happen.

Now you can also see some of this plug mill-out some of the damage during a plug mill-out. And what I mean by plug mill out is you're taking that plug that you have set in the casing out, by either a mill on coiled tubing or a bit, and you're removing that plug.

And where we see damage is where the mill will not go through that part of the casing without damaging the casing. And you can't remove the plug or you have to use a pilot mill or a tapered mill to get in there and remove it. So this is some of the things that you'll see.

Now, the highest... The **when** is further set here by... And just remember here, this is the highest risk area and this risk point is something that I'll come back to.

Now, **where** is somewhat linked to the **when** factors, but it's also impacted by fatigue or fracture linkage from the previous stages. A slight majority of these casing deformations have been reported, and this is ovalling of the pipe. But it's been reported in the heel of the well where it's starting to turn from vertical into the horizontal, and at that first horizontal point, we'll call that the heel.

But in some areas, the report seems to be that they're seeing deformation scattered along the lateral and a few places report more problems in the toe stages. And the **where** on this, also you'll have to think about the causes, and these toe stages are the most difficult to break down, but the heel stages are the ones that see every pressure cycle during this multiple fracture operation.

So there are cases where the deformations are scattered up and down the well. A few say the heel is the most, some say it's just individually scattered and they don't know where it's coming from.

Few of the instances of damage, however, are reported in the vertical section – very few. One area though, that does have some agreement on the damage location is the build area of the well in the deviation point of about 50 degrees towards the horizontal to 80 degrees towards the horizontal.

And in this area, a lot of operators are just avoiding perforating or fracturing in that specific area. And there's some rock mechanics reasons behind this, because in that heel area is also the weakest part of the rock as this bit is coming through there. So that's a little bit about the **where**.

The **why** question, well, that's a little bit more difficult and it's probably the most elusive part: Unless you really study this on a well-by-well basis, and you can identify the most likely damage mechanisms. And this comes back to getting into that risk analysis.

Marty Stetzer: George, is casing damage instantaneous to the fracturing activity, or is it slow to show up?

George King: There is a definite time dependence and the time dependence is in the appearance of the deformation, as previously mentioned in the **when** factors. And what we think is happening here is a combination of formation creep of the shale formations, which can creep over time, just like salt or anything else, except it's faster than a salt creep…where it can start pushing on the wellbore.

And this comes into play where you have a very close clearance between your wellbore and your casing, and you don't have good cement support, perhaps not good centralization. And those factors will show up later on, some of them in the mill-out operations, but some of them will actually show up in the production operation somewhere down the road.

So the time dependence is there. Most damage is seen during the frac, but others report, as I've said, it during the mill-out operation and, a few, in the production side.

Marty Stetzer: You mentioned frac hits earlier. Can fracture-driven interactions cause offset well-casing damage?

George King: The fracture-driven interactions – and I'll just use FDI as a synonym for it – can be a factor when the active well, which is the one you're fracturing, connects with a well… say any of the multiple offsets around there that is unprepared for a direct influx of pressure, volume of fluid, or proppant, actually, carried by the invading frac fluid.

A growing fracture here takes the path of least resistance from the wellbore, where it has the wellbore stress effects and at a little bit higher pressure to break down, especially when you have these fractures too close together. And, also, it will go down the path of least resistance toward the offset well, specifically if you have depleted areas along that well.

And this is where we really ask operators… if you want to solve this problem, put tracers in here to where you can tell how much fluid is coming from specific fractures that were marked with different tracers. This will allow you to map out the areas that are the most depleted, and avoid aligning the perforations in the active well – the new well that you will fracture – with these depleted perforation sets in the old well.

You don't want that to happen because that fracture will follow that frac plane right into your depleted or partially pressure-depleted well, and you'll have a serious amount of damage or production loss possible in those areas.

We look at a couple of things there and we're looking at active, we're looking at the offset well, and particularly looking at geomechanical factors that will enable the fracture connection here. And this is one place where we're really pushing for people to use the tracers and, during the fracturing process of the active well – fill up the well and put pressure gauges to where you can get bottom hole pressure, and you can see the start of a fracture interaction in these offset wells. And if you're monitoring that during the frac job, you can make some changes here, which will save you a lot of problems.

Now, for further information on this, I'd recommend a book that Ali Daneshy has published, and it's called *Fracture-Driven Interactions, Guides for Real-time Analysis and Execution of Fracturing Treatments*. And this is available through Ali, but it's just come out… and if you're having trouble there, it's a very good source.

Marty Stetzer: George, with all of this happening downhole, what recovery steps can the operator take to get more access to the lateral after they notice they have damage?

This has been an area of a lot of discussion with operators coming forward with several different types of solutions to this problem. Some in the design phase that I mentioned, the diameter-to-thickness ratio of less than 12, but others also are using multi-finger calipers in high risk areas, and we'll cover a little bit more of that in a while.

But basically what they're doing is trying to make that wellbore as smooth and as gauge as possible through there. And you have to remember the corrections that directional drillers make, and those are the areas that you want to pay particular attention to. That's before the frac.

Now, during the frac, some companies are keeping a supply of smaller frac plugs to where if they do hit an area where you cannot get the frac plug down as deep as you might, and basically this is just from ovalling, or you could say partial collapse. I hate to use the word collapse because we're not typically collapsing these wells and we're not failing these wells, but we are certainly creating an oval pipe in these wells.

Now, they use a smaller-diameter frac plug with a larger expansion on the outside, and there have been some new plugs come on the market to try to handle that. They may not hold quite as much differential pressure, but they can go through oval pipe and set in some round pipe in joints around it. And typically if you cannot set in a pipe due to just the slips won't engage, go to the next lower joint or the upper joint around them, and you can usually find a place to set your plug.

We're seeing deformations where these plugs will start having problem of around 10% and we've actually monitored some of these ovalties that exceed 20%, so this definitely is a deformation. Now, some companies use the smaller plugs. Some companies use a longer small plug with more sealing ability on that to be able to set up and get it to seal.

Now, the alternative to this, and you're getting away here from the plug and perf and getting into the packer and sleeve… there's been some luck using frac sleeves that can be selectively opened or closed during the entire frac treatment.

So if you have a lot of damage happening in one section, you can close that sleeve, come on up the wellbore maybe 100… 200 feet or more, start fracturing again, and at some point you can close the sleeves up there, go back and open the sleeves in the area where you were having issues and frac there again. So there are some differences you can do in the actual completion design and the approach to making these possible.

Marty Stetzer: George that covers understanding what happens after damage is noticed. What can be done to recognize casing damage potential before or even during fracturing?

George King: Well, what we do at Viking is we start out constructing a workflow of casing deformation risk. And the risk is the outcome here. But casing deformation causes that we have tracked down – and we've done investigation on literally hundreds of different wells for various failures – many of these were during the fracturing process, and we're seeing more and more of these, or more and more work coming into the shop in this area.

But this will help you, this workflow, and you'll start out looking at the geomechanical side, the rock fabric side, the mechanical side from drilling. There are a lot of factors that go in here. And you're addressing what may have caused this? What was the separation of wells, and factors such as that.

And this helps you say, "Okay, wells with this set of conditions actually fail more frequently than wells that don't have this set." And you can find also the set of conditions that minimize the risk. So if you can do this workflow, areas with higher risk can be estimated and labeled so that you might be able to change the fracturing approach to this.

I'm going to throw in there that monitoring your offset well pressures is going to help you, because that helps supply good information on timing. And as I said, timing can happen at any time during the frac, after the frac, during the mill-out, or in production.

So knowledge on that, collecting the data and knowledge is probably one of the best things you can do, but then put it in a workflow to where you can go very quickly through this and spot high-risk areas of the well.

Now, the best application is to treat each set of wells as an independent set. Not the whole basin, not the whole field, just an independent set of wells that appear to react in similar manner. And you can learn what the fracturing pressure changes mean.

And then what you need to do to give the company man on location, and I would suggest to any engineer, get out there, get in that frac van, start asking questions, and look and see what's going on.

When you take this type of approach, you'll learn what pressure changes during the frac actually mean – whether it's a ball, a frac ball that's broken, whether it's a frac plug that's turned loose, whether the casing is starting to create problems from doing the wireline setting of plugs.

But if you have the offset pressure from these wells, you can also see the onset of fracture-driven interactions, and you can react by changing the fracturing treatment on the fly. And this gets you away from the cookie cutter frac approaches where this is frac according to a schedule. Don't do it according to what the fracture design says. You need to put a frac in there that depends on what the formation is telling you via pressure, via rate signals. There's all kinds of things here, but pay attention to those and you'll have much less damage.

Marty Stetzer: George, that was terrific. Thank you so much for your insights. They will surely be valuable to the SPE-GCS audience and our own community of 10,000 EKT Interactive listeners. Do you have any recent articles, SPE papers, or webinars that you recommend for our communities to get more background?

George King: We just finished an application and invitation-only SPE summit… focused on casing damage. And that was completed in late March. Neal Nagel and myself were the co-chairs of that.

But we had, I think almost 70 people from probably 15 or 20 different companies in there, sharing information and commenting on learnings, and also questions about that. So we'll have more of those meetings coming up in the coming months. And look for those, and also for SPE papers.

And I'm going to suggest SPE's OnePetro website to look for papers on the subject. And there is several that address the recognition of these things by considering the pressures from the offset and the active well, and then looking at changes that you make in the design, and what that does to the pressure signal.

And this all comes back to the Nolte-Smith equation as a basis. And then we go on from there, but there's a lot of good information out there in the literature. So, please do some searches and find some good papers on that.

Marty Stetzer: Thanks again, George. If our listeners want to learn more about the SPE Gulf Coast Section, go to www.spegcs.org. You can access recorded webinars and the on-demand library, or support our scholarship program by contributing to our scholarship endowment fund.

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