What Should I do With my Acid?

One of the cheapest things in the oilfield is acid, but one of the most difficult things to reliably achieve maximum value from is acid treatments. A case study where a well offshore in the Gulf of Mexico saw an enormous productivity increase acts as a case history. Many case histories or examples or texts about acid and stimulation dive straight into the process of designing the treatment. Acid usually dissolves something, so it will produce some results. But how do you get the best results? By looking at all the other factors. These are the other factors and the order in which to address them to ensure nothing gets overlooked.

Geology and Reservoir Fluids

What mother nature has for us in the ground is our starting point. This includes the temperature and pressure of the system. Just as important as what the rocks are composed of is how they are organized. A massive carbonate with fractures is going to behave very differently from a sand composed of decomposed carbonate particles even if they have the same chemical composition. In this case there was a poorly consolidated mostly silicon dioxide sand with 190 mD permeability, 9,600 psi (662 bars) bottom hole pressure at 179 F (81 C) containing high API gravity, low viscosity oil about the consistency of diesel and gasoline mixed together. The sand was chemically 'dirty' with a lot of different species of minerals creating potential for side reactions. Sometimes this is THE key area for understanding how to design a treatment because the temperature or the nature of the formation or the crude properties will drive the rest of the decision-making process. One possible problem which presented itself for this well was the potential for fines migration into the gravel pack causing productivity loss, and we will come back to this later.

Current Well and Field Condition

The well was completed with a 4 ½" 250' (76 meter) horizontal high rate gravel packed screen at 18,000' TVD (5,500 meters TVD) and 5 ½" 20# casing to surface. Production was 4,000 bbl. of oil a day with associated gas and no water. This was a new deep-water field, but in a known region/basin. There were several other wells in the field producing at a variety of rates (both lower and higher) all water free on primary production. First field startup was less than a year before this point in time so there was not a lot of general history to work with on the field. Sometimes well and field condition will drive all the decision making. In a thoroughly understood area, well stimulation treatments may all be repeats or minor variations on ones which have shown themselves to be successful in the area. In this case, the other wells in the field all seemed to be performing as expected. However nodal analysis, reservoir modeling, and the performance of other wells in the field suggested that this well was severely underperforming, and that a production of 8,000 BOPD (Barrels of Oil Per Day) could be expected at the current drawdown if it were as productive as the other wells in the field.

Well History

During initial drill in to the formation there were significant losses of fluid to the formation, and sized calcium carbonate was used to reduce the fluid losses. Several rounds of carbonate had to be pumped to get the losses to a controllable rate. This was thought to be cleaned up during the gravel pack acid spearhead. The production packer failed when it was placed on production and before the inflow rate had stabilized. The production packer and tubing were pulled, and a new packer had to be run. Fluid losses of 1-3 bbl. per hour of 9 ppg (1.08 sg) sodium Chloride brine were experienced during the workover, and this resulted in hundreds of barrels of fluid losses while the debris from the failed packer was fished out. When the well was put on production after the workover it produced 1,000 BOPD. This was clearly not what it should have been, and a bullhead acid treatment was conducted bringing the flow rate up to 3,500 BOPD. This was still less than expected so a second acid treatment was pumped, and the rate came up to 4,000 BOPD. Clearly acid was not doing the job. It was hypothesized that a buildup of solid sodium chloride salt had been created in the near wellbore area by a combination of dehydration and osmotic forces, since the well had no free formation water, and this hypothesis seemed to fit the facts of the situation – something in the well not soluble by acid. It was further hypothesized that there may have been some residual debris from the packer still in the well, since removal of the parts had been very arduous, and it was unclear if it was completely successful. Thirdly it was thought that fines had entered the sized gravel pack sand restricting productivity.

Well History part 2

At this point, I was curious about how much calcium carbonate had been used, since the operator engineers kept emphasizing how difficult it had been to maintain circulation on the well during the workover. It turns out that nobody knew for sure. The rig reports noted that it was pumped, but without details on exactly how much – merely the number of pills without detailing how large the pills were or what was in them, so I tracked down the mud additives company and confirmed that they had pumped somewhere on the order of 40 metric tons (45 US tons) of calcium carbonate into the well over the course of the job. Then some more was used in the workover, not recorded, but based on sales figures came up to roughly 10,000 lbs. (5 tons). I spoke to the lease operators and they reported that 'a lot' of material had been produced from the well during cleanup. Upon further investigation, 'a lot' was about 5 bbl. worth, roughly 330 lbs. (200 kg), so about 0.5% recovery at best. The initial acid for the gravel pack job was only about 2,000 gallons (7,500 liters) of 10% HCl acid. The subsequent treatments were 2,500 gallons (9,600 liters) of 15% HCl followed by a second treatment of 2,500 gallons (9,600 liters) of 15% HCl. These treatments were never large enough to dissolve all the calcium carbonate that was put in the wellbore. They may have dissolved some of the carbonate, but even in a perfect world the maximum amount of calcium carbonate it could have dissolved was on the order of 7 tons total between the three acid jobs before it was all spent and inert. The formation still had 38 tons (42 US tons) of calcium carbonate in it.

Solution and Delivery

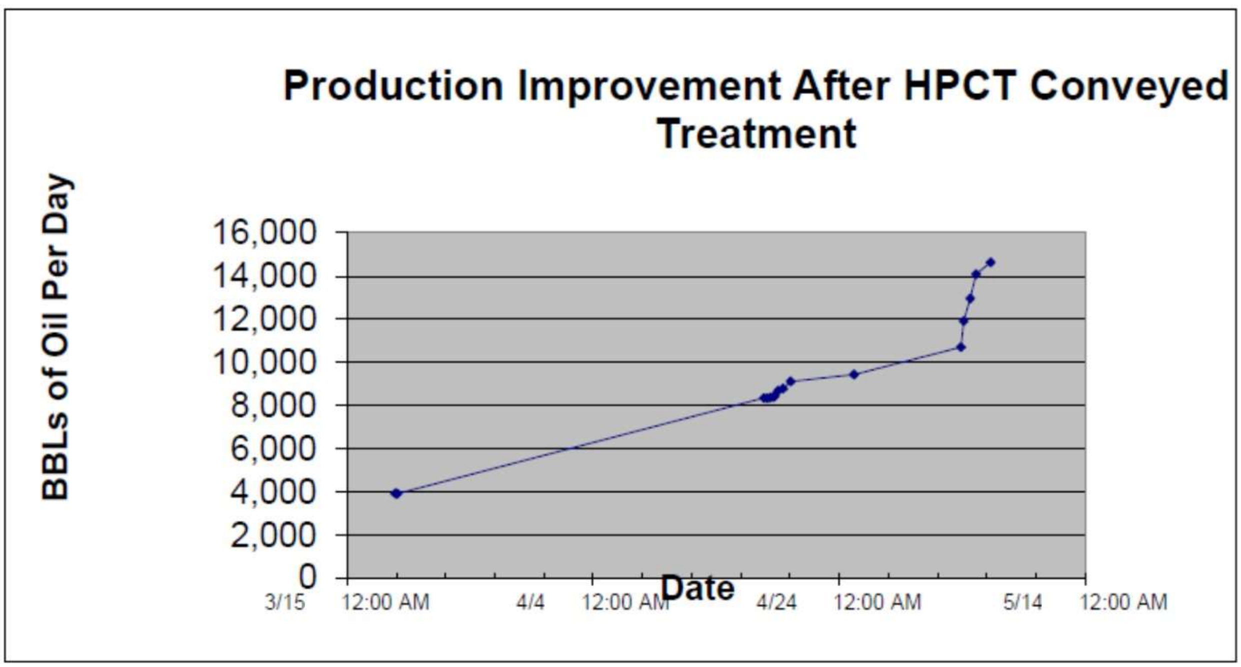
What was needed was more acid – a LOT more acid, and verification that it was at least going to some of the right places. A treatment plan was made to place 25,000 gallons 95,000 liters) of 15% HCl in the formation using jetting tools on coiled tubing to ensure that the acid would at least be washed across the whole screen assembly. This would be enough to at least be possibly capable of dissolving the calcium carbonate known to still be in the formation. An equal volume of dilute ammonium chloride would also be used as a buffer to flush and remove any sodium-based salts which had precipitated and prevent any side reactions. Because there was a rig actively working on the facility the treatment delivery had to be done around the working rig, and a separate mobile crane had to be mobilized and installed on the facility to support the coiled tubing operations, and access to the well had to be gained by use of a motion compensated tower separate from the rig's compensated derrick. Finding space for all the acid was a major problem and was partially resolved by bringing the acid to location as 36% concentrate and diluted on location - an unusual practice offshore, since acid blending with a rig active, and producing wells all in the same place is difficult to do safely. Gaining access to the well was challenging enough that it was not certain that it could be done, much less on a tight schedule. A delay in any portion of the project would have been a major setback because the next few wells the rig was going to work on were in an even worse position relative to the target well, and the rig could not reasonably take a coiled tubing unit into the derrick due to the presence of automated pipe handling equipment.

Chemistry

In this case chemistry was simple, both because it had already been worked out for the previous projects and because ordinary 'off the shelf' additives were sufficient for the operation. No H2S issues, no serious sludging or asphaltene issues, no complex acid formulations, no need for flammable solvents, just lots of acid, soluble salts, and some mutual solvent to aid flowback. At other times, the chemistry of the formation drives fluid selection. Sometimes extreme temperatures dictate what can and cannot be utilized to such a degree that every fluid choice is made by temperature constraints and not by expected success of the treating fluid.

Conclusions

The well came back in at 8,000 BOPD during cleanup which was increased to 15,000 BOPD once debottlenecking of the separator system was completed.



This was double the expected results at half the drawdown, and analysis showed that the well had a negative skin factor. At that point production rate for the well was constrained by the total throughput rate of the facility. The process of conducting the treatment once a decision was made about what to do was reasonably simple – a large logistical challenge but not complex in concept. Figuring out what to do was far from simple. The initial ideas from the operator were to use clay acid to dissolve and immobilize fines, along with a variety of flushes and adjunct acid stages to prevent side reactions with the formation material, which could have been serious. As a service provider this would have been an incredibly lucrative job to perform, but it would not have solved any of the core problems with the well. Only a careful dive into the history of the well with careful questions to a lot of people along the way created the insight necessary to realize the real problem and how to address it. Most stimulation issues are like this – figure out the true nature of the problem and the solution becomes obvious. I hope this informs and inspires you on the next puzzle you need to solve to get the best production from your wells.