Well Intervention and Workover: Practical Examples

You are the proud owner of a drilled, completed and on production oil and gas well. Production is coming in; checks are being cashed and all is right in the world. Or is it? Is your well doing its best? Will it suddenly quit producing in 6 months? Will it present odd problems late in life? Can you predict what they will be? When should you recomplete to a new zone or conduct a P&A? what decisions should be made about the process? What dangers must be looked for? All these questions and worries are a part of the arena of workover and intervention. This is the second in a two-part series about well interventions and workovers. The first part is available here: This second part will look at how the principals introduced in the first part are used to complete a variety of interesting workover projects. A shallow vertical well on a rod pump in California, a directional gravel packed gas well on the shelf of the Gulf of Mexico, and a critical high rate deep-water well which is not what you might expect.

Case Study, heavy oil Bakersfield CA

The very first workover I was ever involved in was a 1,500' (500 meter) depth vertical heavy oil well on steam flood in California. The well was on production, but volumes were low – 1 or 2 bbls a day of oil and ~ 10-15 bbls a day of water. A small diameter rod pump had to be installed to get past damaged casing, and it still couldn't be inserted low enough into the well to reliably get the well pumped down sufficiently to dewater the column of fluid in the well and get the oil floating on top. Nearby wells were making 20-30 bbls a day of oil and 50-100 bbls a day of water. I was an intern, and it was suggested to me by an old hand (not an engineer) that lowering primer cord across the casing and detonating was a cheap 'old school' technique used to try and resolve issues like this. The counter argument was that this could split or hole the casing, rendering the well useless. Fortunately, from a risk perspective the well was already useless. A previous attempt to reperforate the zone failed, because the smallest size gauge ring to simulate 1 3/8" guns would not pass through the very heavily damaged 9 5/8" casing to reach the producing zone, and no larger or lower position for the rod pump could be installed to attempt to reduce backpressure due to the same damage. We decided reluctantly to go ahead with the proposed detonation. My suspicion is that the regular staff planned to blame the failure on the intern if it did not work! This successfully allowed a larger pump to be lowered to a position below the perforations, past the previously damaged area. Production came up to over 50 bbls of oil a day initially, then stabilized at over 30 bbls of oil with a 50% water cut and was still there when my internship was over for the summer.

The job paid for itself in less than a week. If it had failed however, there would not be any reasonably economic way to repair the well – it would have to be plugged and abandoned, and either a new well drilled, or hope that recovery could be made in adjacent wells. The risk of permanently damaging the well was real. The potential consequences of damaging the well were small and the potential upside of success were reasonably high. Gathering additional information about the condition of the well, and the nature of the damage was prohibitively expensive. At prevailing prices for heavy oil, the well was making a gross income of $20 a day. Good quality wireline run cameras were available in the area, and used on a regular basis for wells where they were of value, but the minimum cost to run a camera would have been ~ $5,000 – over the net value of a year of production, and may or may not have been able to lead to a better or different plan to rehabilitate the well. As it turned out, the total cost of the intervention was 16 hours of a truck rig to pull, then re-run the rods in the well, and a single cased hole wireline run for the primer cord coming to a total of under $3,000.

Case Study offshore well Gulf of Mexico

A gas well had been producing 2.5 mmscf/day of gas, 10-15 bbls a day of condensate and 20-30 bbls of water (probably connate or condensed water) from a zone at 11,500' TVD (13,500 MD) when it quit producing several years before, with an estimated bottomhole pressure of 2,500 psi. The well was located on a reasonably sized manned platform with dry hole trees. Slickline Diagnostic work conducted by the field slickline unit had noted the sustained casing pressure in their logs, and had left behind a slickline bailer fish 1,000 ft (300 meters) above the old producing interval which got hung up somehow attempting to bail sand, and a failed gravel pack as evidenced by sand in the wellbore. This combination of complicating factors led to the well being ignored for several years while more pressing matters were addressed. The existing zone still has some reserves booked to it if it can be put in a producible condition. There is a recompletion opportunity 1,500 ft (500 meters) above the existing completion.

- Can the old zone be saved? Is it worth it?
- Is the casing pressure caused by an actual leak? Where? How bad is it?
- Can the new zone be reached without a sidetrack?

Not all these things can be determined in advance. Some of them can be planned for ahead of time. The casing pressure may be diagnosable via a bleed off and buildup without any intervention at all. However, if it is a real leak, it will have to be repaired before the wellbore can be salvaged for productive use. The repair will depend on the nature of the leak, so if a real leak is detected, diagnostics (probably via an E-line leak detection log) should be conducted to come up with a reasonable repair plan. If a repair cannot be conducted in a reasonable way, then the well needs to be plugged and abandoned, or an entirely different leak repair plan needs to be made up if one cannot be executed at this time. An attempt to recover the fish should be made. A stop point in terms of effort and expense needed to be pre-established, since there are other alternatives for returning the well to productivity, and attempts at excessive cost may be value destructive even if the original zone is eventually restored to production. No good plan for dealing with the failed gravel pack can be created until after the fish is recovered, since there is no physical access to it until then. Is the wellbore full of sand? Or is it merely a few bridges? Has screen debris or chunks of cement entered the wellbore? Ideally these decisions will have to be made on the fly, as the workover progresses. If this cannot be done, then a whole separate mobilization and demobilization will have to be done to facilitate the decision-making process. The cost of getting equipment and personnel to and from offshore locations is a considerable portion of the cost of an entire workover. If the old zone cannot be recovered, another 'on the fly' decision should be made to move up hole to the new zone (assuming that the casing situation was resolved). In this example there are three decision points which perhaps in theory might be removed via intense diagnostics and research: Where, and how to repair the casing leak, A precise method of recovering the fish, and exactly what to do and how to do a repair of the old zone's sand control. However, in all 3 cases, gathering the information required to know exactly what to do first has different tradeoffs. Coming up with an exact plan to resolve the casing leak is probably cost effective. However coming up with an exact plan for a method to remediate the lower sand control problem is not, because it must be done after the primary personnel and equipment to resolve the casing leak and the fish have already been committed to work on the project. The process of gathering data, and then deciding would have to be made while these things are all waiting, or a complete restart of the project must be made. For the same reason, the decision to abandon attempts to return the lower zone to production and move up hole should be made on the fly. Sometimes the cost of gathering data before acting outweighs the cost and risk of discovering the actual conditions by attempting to resolve the situation with limited data.

In fact, what happened was the following:

- Prior to the mobilization of any significant personnel and equipment, a small triplex pump was sent to location with a single operator working during the day only to prevent the need to get additional production crew to location to aid the operation and to keep the cost of the operation low, since it might be time consuming, but not require large amounts of actual work. The casing was hooked up to the test separator and a bleed off was conducted. The casing bled to zero and failed to rise significantly over the course of 24 hours. Then the casing was filled with seawater, and the production tubing was filled/loaded with seawater and pressured up to 2,500 psi. This confirmed that the well was still sanded up, and produced a negative test on the casing, at least for areas above the fish, since sand was not present above the fish. After bleeding off the tubing, the casing was pressured up to 2,500 psi and held. This confirmed that the casing was not leaking into the tubing. After this was concluded, it was clear either that the casing pressure was thermal buildup, or possibly that the leak path was deep, below the possible recompletion zone. This allowed the workover to proceed with a reasonable certainty that the well could be eventually placed on production. This process took ~ 6 days at a cost of ~ $10,000 a day total.
- A coil tubing unit with triplex pump, 3 compartment tank, gas buster, and a slickline unit were all mobilized to location. After eight 24-hour days the fish was successfully re-located, baited by slickline, latched, and recovered after jarring on coil. Nitrogen tanks and a pump were sent out, and a nitrified cleanout was started with a slim hole BHA with no external upsets. Progress was made washing sand for ~ 350 ft (100 meters) , when progress ended, well short of the bottom zone. A slickline bailer run came up empty, and the decision was made to run a mill and motor on coil. Without making any new footage, the mill got stuck and torqued up, unstuck, and torqued up a second time. After getting out, a slickline bailer came up empty, but an impression block had various sharp indentations on it. The conclusion was reached that the gravel pack on the bottom zone had suffered a catastrophic failure producing metal screen debris in the wellbore. This process had an all-in cost of ~ $60,000 a day.
- Based on previously agreed upon economic modelling, it was concluded that the lower zone did not have sufficient reserves remaining to justify a major rig workover to pull the tubing, and then wash/mill over the gravel pack, which is a high risk operation. The Coil Tubing unit was demobilized leaving behind the pump and flowback tank, and an E-line unit was mobilized to location. The old zone was isolated with a bridge plug and cement dump bailed on top, and the new zone was perforated and placed on production as a dry gas well. This process took ~ 4 days at an all-in cost of $30,000 a day. The well IP'ed at 4 MMSCF a day, and the price of gas at the time was $3/mcf, yielding a cash flow of $12,000 a day.

Total workover operation, 18 days, $660,000 in 2012, project paid for itself in a few months of production.

Case Study Deepwater GOM

In this case, a large newly developed deep-water field in ` 6,000' (2,000 meters) of water had been placed on production ~ 18 months ago. There were 8 subsea wells connected via riser to a floating production hub. 6 of them were oil producers, and 2 of them were water injectors. TVD from sea surface to formation was ~ 27,000 ft (8,000 meters). The water injectors were there to keep the oil above bubble point to maintain the reservoir in 2 phases with no free gas, and to aid in sweep efficiency. One of the injectors began building up casing pressure. Diagnostics determined that there was a leak path from the tubing to the casing. The leak was very small, and only opened up when injecting at pressures of 3,000 psi or more at surface. Unfortunately, injection above this pressure was required to meet the pressure support requirements for the reservoir, and total injection in this well as taking place at a rate of ~ 40,000 bbls a day. For regulatory and safety reasons, a buildup of casing pressure was not allowed, and it was determined that the leak path was almost certainly below the depth of the subsurface safety valve, indicating that there would not be any way to safely close the well in the event of a major emergency. Without remediation, injection to the formation from this well had to be reduced to below 15,000 bbls a day. This meant that the reservoir pressure in the formation began to drop. If it fell to close to the bubble point, the production of the whole field would have to be reduced by a sufficient amount to prevent any additional pressure drop, estimated at ~ 30,000 bbls a day in lost production until the problem could be repaired. Diagnostics to find the leak needed to be performed but compered to our situation on an easily accessible manned platform the situation is dramatically different. Access to the well is only available by use of a large and expensive semisubmersible rig or drillship. The process of bringing it to location, running riser and a lower workover package with ball valves, wellhead umbilical controls, etc. takes considerable time, and the cost of the rig on a per day basis at the time this was being conducted in late 2013 was ~ $200,000 a day for the lowest cost available rig. The time to mobilize and test was estimated at 5 days, and 3 days to leave location. This meant that arriving on location to conduct work – ANY WORK carried with it a cost of ~ $1.8 million after accounting for supervision, supply vessels and other misc. costs, not including the cost or time of conducting the work itself. The intervention was planned to consist of 3 phases:

- Diagnostics: An extensive suite of logs on cased hole e-line were developed including high resolution thermal scanning to look for heat or cold areas as a sign of leakage, wall loss measurements and precise geometric measurements to look for damaged or compromised tubing threads or base wall problems.
- A plan was prepared, and materials were arranged to attempt to dump a self-healing sealing glue like gel into the production tubing via e-line on the basis of the assumption that a microscopic leak in a thread or other jewelry item might be found. This plan included setting a 'bottom' in the well to catch any gel material which might fall in the wellbore and potentially damage the high injectivity frac-packed zone, and then recovering after it presumably became stuck when the gel hardened.
- A second plan was prepared acting on the assumption that one or more discrete leak paths might be positively identified in different parts of the production tubing. A plan to RIH with CT and isolate them in sequence with an inflatable straddle packer, then inject sealing material into each leak path one at a time. Several subsets of this plan were developed to deal with several different scenarios. This would be more time consuming

than bull heading the sealing material, but more certain since each leak area would be treated individually. It was also considered high risk, since the pressure required to successfully inject material into the leak was likely to be close to the maximum operating pressure of the packer, and there was a risk that some of the sealing material might clog the operating mechanisms of the packer. One of the greatest risks was that use of the sealing material above the subsurface safety valve might result in accidently disabling the safety valve. This would mean that the well could not be used at all for any injectivity until the valve was repaired, requiring a rig to come and pull the production tubing.

When the time came to perform the operation the diagnostic logging information of enormous volume, value, and importance. The logging took over 48 hours in hole under a variety of flow and pressure conditions. Then another 36 hours or so were spent analyzing the results of the logs. This led to a second round of logs and interpretations to make completely certain what was being seen, and to verify the nature of some of the leaks which were discovered. It was determined that there were at least 3 different leaks, one ~ 1,200' (350 meters) above the safety valve, a second one ~ 2,000 ft (600 meters) below the safety valve, and a 3rd one ~ 700 ft (200 meters) below that. Having 3 leaks strung out over a space of nearly 5,000 ft (1500 meters) with one of them above the safety valve was a bad case situation among the ones which were forecasted.

The decision was made to make no attempt at a repair, and instead to schedule a rig to pull and replace the tubing. Total time on location for diagnostics and attempted through tubing repairs 15 days, total cost ~ $4 million. Result: Need for a rig workover with a total cost of ~ $8 million and ~ 25 days of work. Production of 30,000 bbls of oil a day saved/maintained, at $100 a bbl. The total $12 million dollar diagnostic and workover in 40 days of work on location paid for itself in less time than it took to conduct.

Conclusions

In part 1 we identified 3 critical factors that go into a workover: Economic limitations, uncertainty, and irreversibility. In 3 very different examples, we had an opportunity to see how these different factors play out in practice. In some cases, like the land well in Bakersfield, these factors combine to mean that there is nothing to go on but engineering judgement and past experiences. In others like the shelf Gulf of Mexico case, it means 'learning by doing' and applying information as it is learned. In yet other cases, like the deep water case, it means extensive preplanning, and what amounts to an entire campaign worth of workover expenses to gather data about a single well in order to understand what to do to repair it. As always, feel free to bring up any questions or comments – I always like to hear from folks. Stay safe everyone!