In workover and well-servicing situations, well control commands special considerations

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Editor's note: Mr DeBuys, under the auspices of the IADC Well Servicing Committee, prepared this article detailing the substantial differences in well control procedures and challenges between drilling and workover/well-servicing operations.

WHAT DO YOU call an operation that works with live hydrocarbon producing wells on a daily basis? If workover and well servicing sprang to mind, you're right! While conventional drilling usually operates with a mud column sufficient to hold formation pressures in check to prevent an inflow of formation fluids, workover and well-servicing personnel typically confront wells with exposed flow-capable hydrocarbon-bearing zones, and often begin their day killing the well.

This article will focus on fluids used and other differences in operations, well control and equipment between drilling and workover/well services.

I know the majority of the readers of this magazine are the drilling contractors. On occasion, they are called to perform completions and even workover operations. It has been said that drilling is easy; all you worry about are kicks, lost circulation and stuck pipe. Workover and well servicing have these problems and many more, often unknown until you get into the well.

The table on Page 103 contrasts complexities in workover/well servicing with those of balanced/overbalanced drilling operations. These are generalizations, do not include all problems and are not arranged in order of importance.

THE DRIVING ECONOMICS

During a producing well's lifespan, it may go from primary hydrocarbon recovery, i.e., an initial free-flowing well, to one requiring secondary and tertiary recovery techniques, such as pumping and formation stimulation techniques. Equipment may be added or changed out to try to squeeze as much as possible from the formation. This may be a well-orchestrated plan or reactionary, depending on what's going on downhole, sometimes both.

In workover and well-servicing operations, identifying the problem(s) is key. Regardless of what is done, it is of utmost importance to minimize damage to the producing formations and still safely control the well.

The formation is the cash register. There must be enough recoverable oil and gas to warrant financing workover and well-servicing operations, with a reserve to properly abandon the well. Damage the formation, and your cash register contains less, perhaps even ruining the well of economical recoverable reserves.

MUD VS CLEAR FLUIDS

Drilling operations are usually performed with weighted fluids – mud – to prevent the well from flowing. A kick is avoided at all costs. Workover and well servicing often use field water or clear brines. Both fluids have the same function – to keep the well under control while work is being performed and to minimize damage to formations.

Mud consists of a liquid portion, usually water or oil, and solids, such as weight materials, clays and chemicals, to give it desired flow and carrying capacity. Both the solids and liquids may plug and damage the formation. It is possible for the liquid portion to filter into the formation and swell native clays, whereas native field water may not. The solids may form a wall cake, which may minimize the mud's liquid phase from entering the formation and often allow heavier-weight fluids to minimize kick potential.

There have been cases where an overbalance of the drilling mud damages the formation, and workover operations are needed to acidize, stimulate or fracture the formation to get it to produce again.

A workover fluid, on the other hand, is usually clear with few or no solids. It may enter the formation easily, even at the same weight as the original drilling mud or less. Hydrocarbon and formation depletion, loss of the formation's drive mechanism, especially in areas that wells are fractured, all lead to problems between the formation's pressure and the hydrostatic pressure of a fluid used to keep the well from flowing prior to workover.

CONTROLLING THE WELL

There are perhaps as many philosophies on how to keep the well static from flowing while performing workover and well-servicing operations as there are fields. It may be as simple as a pump truck showing up and pumping a volume into the tubing, or the crew just bleeding the well down. But one thing is certain: The best well control method is the pre-work planning you put into it, then the execution of that plan. Poor plan, poor well control; good plan, good well control.

Many wells are still producing, decades after their initial completion, in an environment where not only the surface conditions but also downhole conditions may be more hostile to equipment than originally planned. The effect of downhole harmonics, deterioration of metals and the wear and tear on tubulars, cement and surface equipment often require additional well control concerns.

However, the majority of derrick-type rig-based workover operations are conducted in reservoirs where the driving pressure has long been depleted. Pulling/tripping operations are commonplace to replace or repair downhole equipment. And it's usually the routine operation that has unanticipated well control problems.

Often, detecting a problem depends on different criteria than those used in drilling (e.g., increase in flow, pit gain, etc). It may be popping, pinging or other sounds from the tubing or well, change in type or color of fluids from the well, smell or other signs and indicators that may signify the onset of a well control event. Other areas may have ongoing formation injection processes, and if a well is opened prior to allowing the pressures to subside, a well control event may occur.

This may be compounded by high-temperature (e.g., steam and fire flood injections) operations with equipment and fluids hot enough to scald unwary or untrained personnel.

This discussion will be focused on derrick-type rig-based workover operations where conventional well control methods (e.g., wait and weight, driller's, concurrent, bullhead, etc) aren't typically utilized, such as pumping equipment, weight materials and mixing facilities may be nonexistent in the area or not readily available. Some of the techniques unique to workover include the "pill and kill," "rolling the hole" and "trickle"

COMPLICATION	WORKOVER AND WELL SERVICING	DRILLING
Cementing	✔	✔
Corroded/damaged tubulars	✔	X
Damaged casing	✔	X
Daylight operations	✔	X
Fish downhole	✔	X
Formation damage	✔	✔
Formation pressure and hydrocarbon depletion	✔	X
Fractured formations	✔	X
Gas at surface	✔	Not desirable
Good mixing/pumping facilities	X	✔
High day rates	X	✔
High potential for blowouts	✔	Efforts made to minimize
High potential for kicks	✔	Efforts made to minimize
Kick Detection Equipment	X	✔
Kill fluid on location or ability to mix it	Not always	✔
Logging	✔	✔
Lost circulation (LC)	✔	✔
LC mud and brines	✔	✔
Multiple supervisory personnel	X	✔
Oil at surface	✔	Not desirable
Operations start with killing well	✔	X
Parted casing	✔	X
Pollution potential from oil/gas flow	✔	X
Potential for damaging formation	✔	✔
Pressure at surface	✔	Not desirable
Pumps on location	Not always	✔
Re-completing and perforating	✔	X
Re-establish production	✔	X
Several trips per day	✔	X
Stuck pipe	✔	✔
Swabbing (intentional)	✔	X
Swabbing (unintentional)	✔	✔
Unweighted "clear" fluids	✔	✔
Weighted drilling fluids	✔	X
Well Kill	✔	X
Well stimulation	✔	X
Weight material on location	X	✔
Wirelining	✔	✔

methods. Their use and effectiveness in controlling the well largely depend on the type of formation, type of fluids produced, well pressures and experience in the area.

The pill and kill technique usually uses field brine as the controlling fluid. A sufficient quantity is pumped into the well to keep it static, allowing workover operations to proceed. The brine may be pumped either down the tubing, casing or both, usually the side the pressure is on. The volume pumped usually is adequate to provide sufficient hydrostatic pressure to prevent the well from flowing.

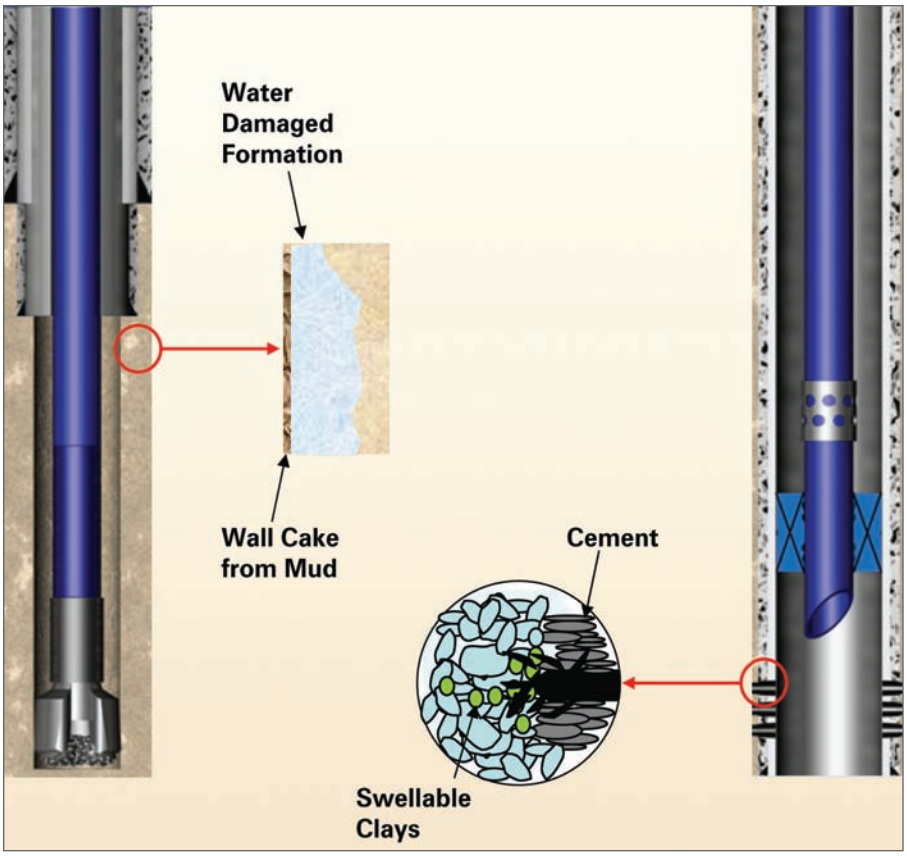
Some formations may slowly accept the control liquid's water and will begin to flow after a while. Still other areas may use heavier brines to keep the well static. In certain areas, concerns also exist regarding the stability of a fluid left in the annulus. Over time, particles within a completion fluid, packer fluid or drilling muds may settle out or fall down to the top of the packer and can damage formations once the packer has been released. It's almost as much art as it is science, and personnel working in the field are experts on fluid type selection and how to keep the well static.

The rolling the hole technique is used to capture the oil inside the tubing. By pumping field brine into the annulus, the well will naturally "U-Tube" as the heavier brine displaces a lighter oil up the tubing. Once the brine reaches surface, workover operations can begin.

The above techniques may be inadequate, especially when tripping out of the well. The level of the controlling liquid's hydrostatic may drop due to the tubing's displacement to a point where the well may begin to flow. Also, swabbing is a concern when pulling tight clearance equipment downhole, such as packers, and is also dependent on the trip rate. Faster is not always quicker if a well control event takes place.

When losses to the formations and/or tripping displacement are concerns, some operations use a trickle method. This can be as simple as a hose connected to a nearby brine storage tank to operations involving pumps and pits with weighted brines. The function is to ensure that some hydrostatic pressure is present to keep the well static.

This table compares general complexities encountered in workover/well servicing vs balanced/overbalanced drilling.



The water portion of muds or brines can invade formations and create many problems, from simple losses to damaging zones that may require remediation efforts.

Well control equipment: I've been fortunate over the last several years to be involved in a project that has brought me to many of the fields, operators and workover operations around the US. From these visits and reviewing the well control equipment on location, one thing was very evident. The presence, quantity, condition and maintenance of the BOPe rest squarely on the operator and their concerns and policies.

Third-party equipment, equipment owned by the contractor and even equipment owned by the oil company were observed in various conditions and states of repair and disrepair, both new equipment and ones older than me. And, since many marginal wells are routinely put on or off line depending on the spot price of oil, equipment selection, rental and usage are often closely tied together. Often environmental concerns are the driving force behind mandatory and additional equipment selection.

In many fields, test pumps are unavailable and the BOPe moved from well to well with function testing as the only test performed, and it is not uncommon for equipment to stay in the field for many months without maintenance or repair shop intervention. Of course, there are also many operations where strict API testing and recommendations are followed as well.

FINAL OBSERVATIONS

Many "informal statistics" from discussions and interviewing crews and operational personnel show a few key points:

1. Personnel (crews, consultants and company men) need proper training on the type of equipment, its use and how to operate and properly maintain it.

2. Many companies need to review and perhaps revise policies for well control equipment selection, testing and re-certifying it on a regular basis.

3. Forward planning meetings between the operator and contractors are necessary. A review of current policies and information exchange (e.g., bridging documents) is necessary for safe and environmentally friendly operations.

4. Peer pressure needs to be evaluated. The old adage of "hurry up and get it done" only elevates risks. If personnel understand the consequences of their actions, they understand the risks they undertake.