Vertical drop bar assists snubbing applications

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A NEW METHOD of sealing tubing for snubbing operations is now low-cost and safer than previous methods. This new vertical drop bar plug (VDBP) system uses a simple bar drop to remove the plug and requires no outside intervention, such as pumping or wireline.

The new VDBP system for sealing tubing in snubbing operations is low-cost and safer than some other methods available.

The simple bar drop plug-removal system requires no pumping or wireline intervention.

If the drop bar fails to dislodge the sealing plug or a customer elects not to drop the bar, the plug can be expelled using normal pumping procedures.

The components of the VDBP system. The new plug has one O-ring with a back-up ring in an external groove on the plug. The O-ring seats inside a specially-built collar threaded on the end of the tubing. Two small shear pins help hold the plug in place while running in the well.

Snubbing, or deploying production tubing into live wells, is a common operation in gas well completions. In these wells, the casing has been perforated and usually the well has been stimulated through the casing.

As a result of the open perforations, tubing must be run into the well with a self-contained snubbing unit or a hydraulic rig assist unit, otherwise the well will have to be killed.

Well control while running tubing is critical for environmental and safety reasons. To deploy tubing into live wells, the lower end of the tubing must be sealed off to prevent produced fluids from flowing back up the tubing. Several different techniques are used to provide this seal.

The three most common methods are discussed in this article, and a new tool is discussed that overcomes some of the drawbacks of the common methods.

SEALING METHODS

The most common method of sealing the lower end of the tubing is to install a ceramic or glass disc in a receptacle on the end of the tubing while snubbing in the well.

When the tubing is located at the proper depth in the well, the discs are broken by a drop bar.

After the disc is broken, the well can be put on production. Halliburton safety regulations do not permit the use of ceramic or glass discs because they can break from rough handling or from the extreme pressures applied while snubbing the tubing in the well.

One alternative to ceramic discs is to run a slickline plug in a nipple while snubbing in the pipe.

After landing the tubing, slickline is used to retrieve the plug. Operators are often wary of this option because of potential retrieval problems. The slickline unit also adds additional cost to the job.

Another option is a pump-out plug. These plugs are run in the bottom of the tubing while snubbing in the well, then blown out of the end by applying pressure inside the tubing.

While this is a safe method, customers often do not like it because it requires a pump and fluid or gas on location to expel the plug. The additional equipment and personnel requirements add to job costs.

Halliburton can now offer customers a less expensive alternative that combines the best features of the other methods.

VERTICAL DROP BAR

The typical candidate well needing snubbing in the Texas/Oklahoma operating area has these parameters:

Total depth.........12,000 ft (vertical)

Tubing size.........2 3/8-in. with a 1.995-in. ID

Maximum BHP..........6,000 psi

The tubing is normally run in and left dry before expelling the plug or breaking the disc. Knowing that most wells will have dry tubing before being brought on line, Halliburton engineers proposed using a drop bar to dislodge a sealing plug on the end of the tubing.

Using this new vertical drop bar plug (VDBP) system, the well could be brought on line without the need for additional equipment such as pumps or slickline units. Additionally, snubbing operations could be performed safer than with a fragile ceramic or glass disc.

Drop bars have been used in the oilfield for years. Most of these drop bars are made from steel and tend to be at least 2–3 ft in length.

Operator feedback indicated that these drop bars would not be practical for the new VDBP system because of their interference in operations later in the life of the well. The primary concern was their lack of drillability.

This factor led Halliburton engineers to design a bar from a drillable material and to keep the length minimal.

Determining this length was key to making the new system work; the bar had to have enough mass and velocity to expel the plug.

The sealing plug also had to be designed for a minimal amount of knock-out force. It also needed to be drillable.

The new plug has one O-ring with a backup ring in an external groove on the plug.

The O-ring seats inside a specially-built collar threaded on the end of the tubing.

Two small shear pins help hold the plug in place while running in the well.

CASE HISTORIES

Case Study 1—June 2003, East Texas

This well was producing up the casing from perforations near 9,400 ft at a rate of 1.4 MMcf/d as the 2 3/8-in. tubing was being snubbed in the well.

During snubbing operations, the wellhead pressure was 950 psi.

Once the tubing was landed, the Halliburton rig assist unit was rigged down.

After the wellhead was in place, the master valve and a secondary valve were opened so the bar could be dropped.

Halliburton's proprietary drop bar software predicted that the bar would contact the sealing plug in 30 seconds. Approximately 30 seconds after dropping the bar, a small blow of gas was detected at the surface. The master valve was shut at that point.

The tree cap was installed next on the wellhead along with a pressure gauge. Ten minutes later, pressure was up to 750 psi.

Case Study 2—August 2003, East Texas

This well was producing up the casing from perforations around 9,500 ft at a rate of 1.0 MMcf/d. The flowing pressure while running the 2 3/8-in. tubing in the well was 1,000 psi.

When the tubing was landed and the wellhead was installed, the bar was dropped.

Approximately 45 seconds after dropping the bar, gas was detected at the surface. After closing the valves and installing a gauge, the pressure had built up to 1,000 psi.

Case Study 3—August 2003, East Texas

This well was also being produced up the casing from perforations near 9,500 ft. The 2 3/8-in. tubing was being run in the well as the well produced 1.0 MMcf/dat a flowing pressure of 1,800 psi.

After landing the tubing, the wellhead was installed and the valves were opened to allow the bar drop.

At 40 seconds after dropping the bar, there was gas at the surface and the valves were closed. A gauge was installed and the valves were reopened to reveal a wellhead pressure of 1,800 psi. ■