KENNETH MCCLELLAND, SCHLUMBERGER, USA, EXPLAINS THE VALUE OF TAKING GUESSWORK OUT OF STIMULATION DESIGN.
An operator in California encountered an issue where production from its oil and gas wells was suboptimal. A practical solution was at hand; stimulate the tired formations with acid treatments to enhance their permeability. The only thing missing was accurate formation pressure and temperature data.

The parameters that existed early in the field's history were no longer valid due to years of production. Average field bottomhole pressure was low, and the general practice had been to estimate bottomhole pressures from wellhead pressure.

When dealing with mature fields it is useful to consider the situation that existed when the fields were discovered. Formation evaluation was not as advanced as it is today. Logs and test gear lacked the resolution and accuracy that modern technology has provided, and the conventional wisdom was to assume that all formations were isotropic and homogeneous. Geoscientists knew that this was not the case, but in those days the only way they could interpret the measurements they acquired was to make assumptions. Log analysis in the early days was anything but an exact science.

For decades, producing wells' downhole conditions were estimated by extrapolation of surface measurements. An alternative was to run production logs, and in many cases these provided accurate downhole data, but the decision to run downhole diagnostic services was often tabled because of cost or production downtime concerns.

**Downhole 'eyes' were needed**

A family of real time diagnostic services that could be run simultaneously with coiled tubing operations was needed to give engineers a way to 'see' what was going on downhole. Using dynamic measurements, the engineers could adapt and customise well treatment parameters and techniques to match the situation they observed. They could make operational decisions while the means to act on them was still in the hole and opposite the target formation.

Six separate services were introduced under the ACTive* family of live downhole coiled tubing operations. At the heart of the service is broadband fibre optic telemetry that allows simultaneous transmission of real time data from a variety of sensors placed in the tools comprising the bottomhole assembly. The capabilities of the new services were:

- To monitor injection rates, downhole pressures and temperatures of matrix treatments to maximise fluid penetration, enhance diversion and optimise treatment volumes.
- Thoroughly clean out completion and treatment debris using differential pressure readings to avoid formation damage, and minimise the number of trips and operating time, while ensuring thorough removal of fill.
- Ensure optimum well performance with accurate depth control and target coverage in a single run while controlling hydrostatic balance to minimise formation damage during perforating operations.
- Ensure efficient, on depth setting of isolation devices in a single run, controlling differential pressure across the seals to ensure their integrity.
- Improve the efficiency and results of nitrogen lift jobs by continuous monitoring of wellbore pressure while avoiding solids production.
- Enhance all ACTive services by including distributed temperature surveying (DTS) to provide a 3D time/temperature profile across the entire well to monitor treatment placement and production performance.
Operators could choose from the above array of services to match whatever problem they were experiencing. All services were capable of being delivered with a coiled tubing field unit. The new generation of coiled tubing services provided precise control of intervention operations during matrix stimulation, perforating, hydraulic fracturing, cleanouts, nitrogen lifts, cementing and conformance services. It is suitable for all wells including oil, gas or injector/disposal wells.

What was the exact nature of the problem?
A California operator had a field whose wells had been completed in long heterogeneous intervals, in many cases greater than 1000 ft (305 m). Because of the reservoir’s heterogeneity, conventional matrix treatments did not achieve the desired affect because there was no way to know where the acid was going or a reliable means to divert the treatments to the most needed intervals.

Typically, the most effective treatment technique was acidisation, using nitrogen generated foam diversion to ‘steer’ the treatment into previously untreated zones. The procedure often involved setting a slotted liner or perforating a long interval in the horizontal section of the well. An acid treatment was bull headed into the well, typically with foamed acid or nitrogen foamed diversion. But without accurate foreknowledge of bottomhole pressure, it was problematic to generate the correct foam quality. As production logs are not available, determining where to spot the foam was also guesswork. The technique of calculating foam quality on the fly using measured circulating pressure was also problematic as it led to inaccuracies based on assumptions with respect to friction.

Without a measured bottomhole pressure, treatments were based on guesswork, and as a result, many failed to meet operators’ expectations. In fact, post job evaluations of foam quality showed that some wells were treated with as little as 30% foam quality instead of the minimum specified 70% due to using outdated pressure data.

What is factual data worth?
Data inaccuracy was suspected as the main factor affecting the inability to generate and spot the foam diversion where it was required. A typical chart of downhole conditions illustrates the problem (Figure 1). Real time pressure measurements from the ACTive Live system revealed actual bottomhole pressure to be 300 psi rather than the expected 1200 psi. Over a 100 ft (30.5 m) interval, annular bottomhole pressure varied from 300 - 500 psi, then declined to approximately 375 psi. In the same interval, real time bottomhole temperature variations were used to profile the interval and show which zones were taking the treatment. At no time did pressure approach the estimated pressure.

Using the real time pressure and distributed temperature data, well treatment engineers were able to profile the cooling effect of the treatment opposite the target formation (Figure 2). Armed with accurate bottomhole pressure data, they were able to adjust pump rates to meet the specified foam quality percentage. By measuring and interpreting dynamic downhole conditions in real time as the treatment was ongoing, results could be optimised. The entire intervention was conducted with a single coiled tubing trip into the well. Accordingly, 5 hrs was saved over that of traditional methods, and an estimated US$ 10 000 in nitrogen costs was saved.

The implementation of high bandwidth, optical fibre telemetry gives unprecedented control of field operations and downhole processes. With order of magnitude improvement of telemetry rates comes the ability to profile well production using distributed temperature sensor technology. Real time decisions are enabled while tools are in the well, providing the ability to react to real time observations. Typical operational problems such as formation damage, stuck pipe and non-productive time can be avoided, and experience has shown that wells get back online faster with reduced treatment costs. Having real time visualisation capabilities gives engineers the confidence to act to control downhole operations to produce the desired results in the least amount of time. An added benefit was the ability to apply the accurate bottomhole pressure data to aid in candidate selection of subsequent field wells, thus maximising intervention effectiveness while minimising costs.

Note
*Mark of Schlumberger.