SUBSEA SURVEILLANCE

Brian Holland and Gerry Coghlan, Centrica Energy, UK and George Brown, Gary Rogers, Scott Anderson, Emmanuel Balster and Martin Rafael Figueroa, Schlumberger, UK, show how using DTS for subsea well surveillance can heighten understanding whilst reducing risk.

In a worldwide first, a permanently installed optical distributed temperature sensor (DTS) system has been run subsea, and fibre-optics have been used for appraisal purposes with DTS readings during an extended well test. Using an optical DTS system to monitor the extended well test in a North Sea high pressure, high temperature (HPHT) subsea appraisal well enabled Centrica Energy to survey the completion integrity and flow characteristics of the well in real time, leading to a clearer understanding of reservoir performance while saving rig time and eliminating the health, safety and environmental risks that would have been associated with a well intervention. Using a new technique to monitor reservoir intervals below the packer assembly along tubing-conveyed perforating guns, information was obtained regarding reservoir zonal performance in a section of the well where production logs could not be run. The DTS system was used to monitor flow from different reservoir intervals throughout a two-week extended well test to compare actual reservoir flow profiles with modelled predictions.

Planning and drilling the appraisal well
An appraisal well was drilled in a fluvial and extremely heterogeneous reservoir in the Triassic Skaggerak formation in the UK sector of the North Sea to assess the reservoir productivity and quality of a previous discovery and to confirm the northward extension to the field. A previous well indicated significant oil in place, but reservoir productivity remained uncertain. The new
Appraisal well would also enhance knowledge of the zonal flow contribution throughout the reservoir to help distinguish between reservoir scenarios.

It was determined that both an extended well test and a reservoir flow monitoring device would be necessary to meet the well objectives. Initially the operator considered using conventional production logging to provide data. However, the high-angle well trajectory (a 60˚ borehole to maximise reservoir exposure and permeability thickness in the layered, low-permeability reservoir), HPHT reservoir fluids and probable requirement for multiple passes made it necessary to use a DTS system instead. An electrical downhole temperature and pressure gauge was also specified. All log data were to be acquired with a logging while drilling (LWD) system that consisted of standard quad-combo sensors as well as azimuthal density imaging and nuclear magnetic resonance (NMR) tools. The NMR data in particular were expected to provide a base-case permeability profile throughout the well.

The appraisal well was drilled without incident, and depth, borehole trajectory and net pay were as planned. The temperature and pressure gauge was connected to a data-logging device on the wellhead to provide long term pressure build-up data after the rig left location. This allowed the data to be collected three months later for transient pressure analysis. All LWD data were collected, and the NMR log provided a permeability profile, which was used as a reference for the DTS calculated flowing profiles (See Figure 1).

**Installing DTS system and fibre**

A DTS system with an integrated fibre-optic electrical high temperature cable was installed while running the completion within a 3/4 in. tube with 11 mm x 11 mm outer encapsulation. The DTS system recorded a temperature measurement every metre along the length of the optical fibre by analysing backscattered Raman wavelength light from a pulsed laser source. The resulting temperature profile was then interpreted to provide information about production profiles in the well during production and shut-in. Because the data were continuous, production changes with time could be seen as a consequence of changing reservoir conditions. Using a new technique, reservoir intervals were monitored below the packer assembly along tubing-conveyed perforating (TCP) guns to obtain information about reservoir zone performance where production logs cannot be run.

The fibre-optic cable was run from the bullnose assembly to the packer assembly then cut and the encapsulation was removed prior to passing the cable through a port in the packer assembly. A pressure-testable splice assembly was used to terminate the cable tail to the electrical quartz gauge assembly installed on the gauge mandrel above (See Figure 2).

The assembly incorporated a newly designed splice connector with a glass-to-metal seal assembly that provides an inline pressure barrier to prevent losing the electrical gauge and fibre readings above the gun assembly if the cable is

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**Figure 1.** Logs for appraisal well logs, including NMR log. (Image courtesy of Schlumberger).

**Figure 2.** Downhole gauge assembly. (Image courtesy of Schlumberger).
damaged while firing the guns. The hybrid electrical-optical line is split into two dedicated lines, fibre-optic and electrical, at the electrical-optical splitter (EOS) assembly and is terminated below the tubing hanger using fibre-optic and electrical connectors. In the North Sea well, these interfaces were crossed over via harnesses to a fibre-optic remotely operated vehicle (ROV) connector and separate ROV connector for the electrical system. While deploying the subsea Christmas tree and monitoring the data during the well test, separate umbilical hotlines were used for the electrical and optical systems. The pressure data were then recorded and stored using an acoustic data-logger system on the Christmas tree bonnet, which enabled the data to be retrieved after the rig left location (See Figure 3).

The design included the option to drop the guns and run a production logging test in the event that the DTS would not deliver. In such an event, the glass-to-metal seal would protect the pressure-temperature gauge from being affected by the guns firing or from damage while entering the liner.

Data were recorded continuously from both systems offshore and sent onshore for interpretation. The cable was secured to the 5 1/2 in. and 4 1/2 in. tubing with specially designed cross-coupling protectors installed at every box coupling from the tubing hanger, across the assemblies and guns below the packer. The protector clamps were standard above the packer but were specifically designed for the TCP guns to provide a small outer diameter to allow reservoir fluids to flow. Positively locating the clamps on the gun scallops would prevent any clamp movement. This protector design was successfully tested in a quarry with actual guns before deployment in the well. Figure 4 depicts the DTS temperature measurement installation over the sandface.

Significant testing was performed on the monitoring design and system in preparation for the first subsea deployment. In addition to quarry testing the guns and DTS, full system testing was conducted with the subsea tree, interface TCP/monitoring mock-up, subsea interfaces and connectors.

**Monitoring completion integrity during well start-up**

DTS data can be used to monitor a well's completion integrity and the performance of gas lift valves during flowing or shut-in conditions. Gas flowing through a valve produces a Joule-Thompson cooling effect, which enables identification of valve location and any leak through the valve if it occurs. Although gas lift mandrels and valves were installed in this well, they were not required in the scope of the well test.

Four tubing pressure tests were performed before the guns were detonated, which produced leaks with rates around 10 psi/min. each. The DTS data identified temperature anomalies at different gas lift valves in each test, indicating fluid leaks at the valves when the wellbore pressure increased above 9000 psi. No temperature anomaly was observed at the packer depth, indicating no packer leak. Understanding that the leaks occurred at the valves, rather than elsewhere in the completion string, saved considerable rig time over what might have been needed to identify the problem by other means. Temperature data at the leakage points were monitored continuously throughout the well test to provide information on the status of the leaks (see Figure 5).

When the guns were fired, fibre-optic sensor data confirmed correct gun position and detonation of all the guns. Pressure rise in the tubing confirmed connection to the reservoir. During three additional build-up periods, significant wellbore pressure changes took place, and the DTS data again identified leaks at some of the valves.

**Analysing DTS flow contribution**

The well was opened to flow for 15 hours. From the pressure build-up analysis, the reservoir permeability was interpreted to be 1440 md.ft, and the flowing drawdown was of the order of 3000 psi. This drawdown should generate a very large (approximately 10 °C) Joule-Thomson warming effect in the oil.
as it flows toward the wellbore. However, in this case, the oil lost heat to the surrounding reservoir layers by conduction in the relatively thinly layered reservoir. Therefore, the actual temperature observed at the wellbore was much lower than that predicted by drawdown Joule-Thomson warming alone. To resolve the issue, the well team used DTS to directly measure the Joule-Thomson warming temperature during shut-in periods. When the well is shut in, the reservoir zones heated by the Joule-Thomson warmed oil will heat the liquid in the wellbore to their temperature and that temperature can be measured directly with DTS. This effect only occurs immediately after the well is shut in. Using the measured Joule-Thomson inflow temperature instead of the calculated one enabled layer permeability to be adjusted until a match was obtained with the flowing DTS data, resulting in a flow profile calculation.

The Joule-Thomson shut-in inflow temperatures were used to calculate the axial model temperature as a function of the flow contribution from each zone, which is determined by the zone reservoir pressure, permeability, and fluid properties. With the inflow Joule-Thomson temperatures defined, zone permeabilities were adjusted until the thermal calculated axial temperature matched the measured DTS data. The output was the measured flow profile shown in Figure 6. The same technique was repeated when a second shut-in occurred and again during the final shut-in, with results similar to those of the first shut-in analysis.

Figure 7 compares the flow profiles calculated throughout the well test, with the profiles normalised immediately above the reservoir to allow contributions from individual reservoir zones to be compared. The results of the analyses showed that all reservoir intervals that had been expected to flow (based on the NMR cumulative permeability log) were contributing, although the magnitude of the contribution was not as predicted and was changing over time. Comparing the real time flow profile, enabled by analysing DTS data with previous modelled solutions based on NMR permeability, enhanced understanding of the reservoir and its performance and provided Centrica with insight that can be used to improve the reservoir model and optimise new well placement.

**Note**

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