Downhole Temperatures from Optical Fiber

Send a pulse of light through a strand of optical fiber running inside a wellbore, and the well's temperature profile reflects back. This is both the promise and reality of distributed temperature sensing in the oil field today. The many uses for this data are taking fiber-optic technology into the forefront of production monitoring and diagnostics.

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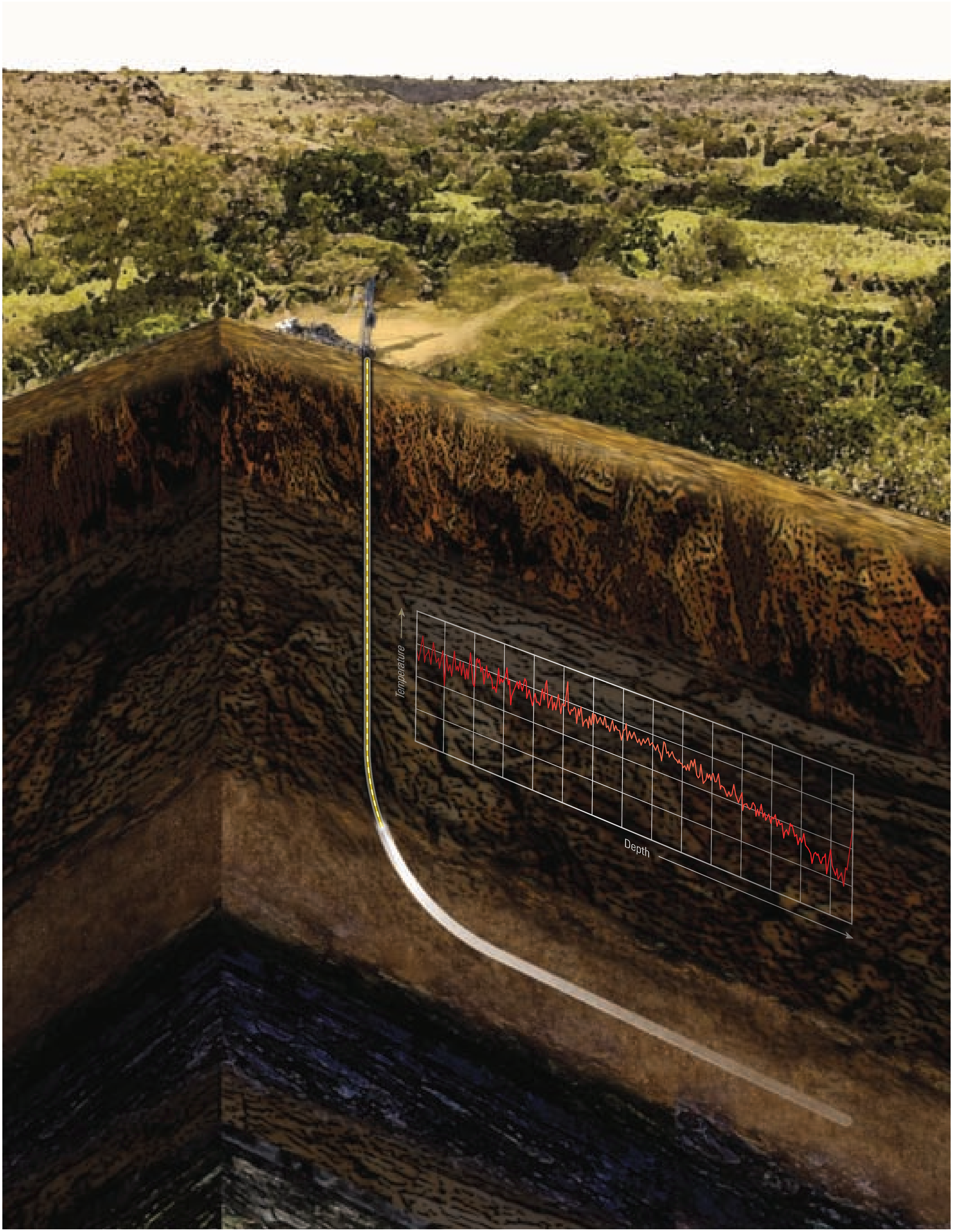
1. Leonardon EG: "The Economic Utility of Thermometric Measurements in Drill Holes in Connection with Drilling and Cementing Problems," *Geophysics* 1, no. 1 (January 1936): 115–126.
2. For a discussion of permanent downhole fiber-optic sensors: Al-Asimi M, Butler G, Brown G, Hartog A, Clancy T, Cosad C, Fitzgerald J, Navarro J, Gabb A, Ingham J, Kimminau S, Smith J and Stephenson K: "Advances in Well and Reservoir Surveillance," *Oilfield Review* 14, no. 4 (Winter 2002/2003): 14–35.

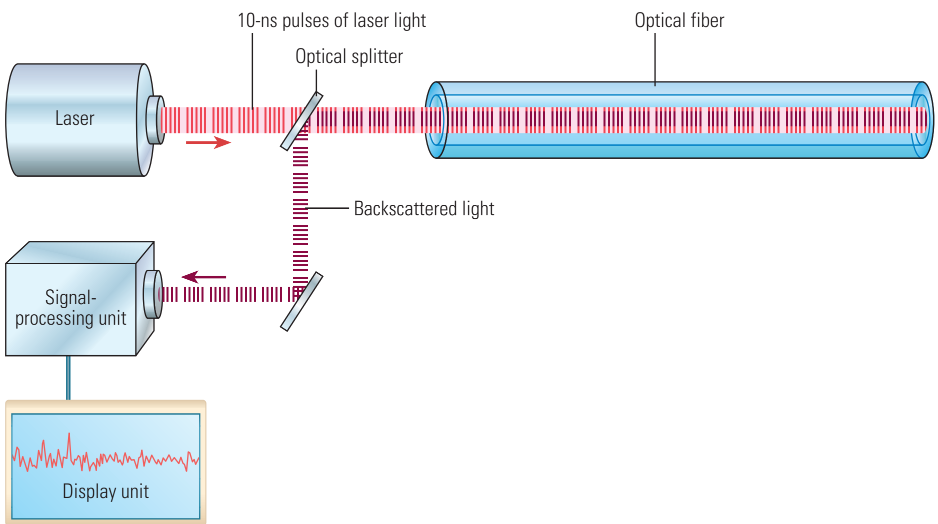
Temperature plays an important role in many downhole processes, and thermal measurements have long been used to monitor the performance of producing wells. Indeed, since the 1930s, engineers have used wellbore-temperature data for calculating flow contributions, evaluating water-injection profiles, diagnosing the effectiveness of fracture jobs, finding cement tops behind casing and identifying crossflow between zones.[1] For many years, the popularity of this very basic measurement was largely overshadowed by other, more exotic measurements obtained through sophisticated suites of logging tools. However, the development of fiber-optic technology has helped spur a resurgence of interest in temperature measurements.

Though first used in the oil patch as a medium for transmitting data and commands, optical fiber has evolved into an intrinsic downhole sensor. During the 1980s, researchers in fiber optics developed a means for measuring temperature along the length of the optical fiber, and this technology was integrated into certain types of oil and gas completions by the early 1990s.[2] Requiring no moving parts or downhole electronics, distributed temperature sensing (DTS) relies on a laser beam and a continuous strand of optical fiber to collect spatially distributed temperature data.

Rather than recording a single temperature snapshot during occasional and infrequent wireline logging runs, a fiber-optic DTS system can obtain extremely sensitive wellbore-temperature measurements at regular time intervals along each meter [3.3 ft] of a well. This uniform sampling enables the DTS system to pinpoint the time and position of temperature changes as they occur, improving understanding of the processes that are taking place inside the wellbore.

This article describes the workings of a distributed temperature sensing system and discusses how knowledge of a key principle governing the thermal behavior of oil or gas in wellbores helps engineers deduce what is happening downhole.


Temperature
Depth



^ DTS process. The DTS laser shoots bursts of light down the length of the optical fiber. Some light returns in the form of backscatter. The backscattered light is split from the incident pulses and filtered into discrete wavelengths. Because the speed of light is constant, a log of the backscattered light can be generated for each meter of the fiber.

DTS Basics

In its most basic form, a DTS system comprises a strand of optical fiber, a laser light source, an optical splitter, an optoelectronic signal-processing unit and a display unit (above). The fiber-optic strand is actually housed inside a protective tube, or carrier. A strand is hair thin—only about 100 microns thick—and has a central core of silica glass, some 5 to 50 microns in diameter. The core is surrounded by an outer layer of silica known as cladding. The silica composition of the cladding is doped with other components—such as germanium or fluorine—to alter its refractive index and light-dispersion properties.

A laser launches 10-ns pulses of light (an interval equivalent to nearly 1 m) down the fiber strand. As each input pulse travels through the strand, its light is reflected along the boundary between the core of the fiber and its cladding, through a phenomenon known as total internal reflection. The core has a higher refractive index than the doped cladding, and light that strays from the centerline of the core will eventually strike the core/cladding boundary at an angle that guides the light beam back toward the center.

However, a fraction of that light is nonetheless scattered as the pulse travels down the fiber. Light can be scattered by density fluctuations or minute compositional variations in the glass—through a process known as Rayleigh scattering—or by acoustic vibrations that change the refractive index of the optical fiber—known as Brillouin scattering.

For the purpose of DTS, the most important mode of light scatter is a third type called Raman scattering, which is caused by inelastic collisions of photons with molecules in the fiber medium. These collisions alter the molecules' vibrational-energy states. A scattered photon may either lose energy to the molecule and raise it to a higher vibrational-energy state, called Stokes scattering, or it may gain energy by moving the molecule to a lower vibrational-energy state, called anti-Stokes scattering (next page, top).

A portion of this scattered light is reflected back along the fiber toward the laser source. Along the way, a directional coupler separates the input light pulse from the backscatter signal. The returning signal is then sent to a highly sensitive receiver, where the Raman wavelengths are filtered from the dominant Rayleigh and Brillouin backscatter.

The energy transferred in Raman scattering between the scattering molecule and the photon is temperature dependent. The Raman signal comprises two components—the Stokes and anti-Stokes wavelengths. The longer-wavelength Stokes signal is very weakly temperature sensitive; however, backscattered light at the shorter anti-Stokes wavelength is strongly temperature sensitive. The ratio of these two signals is directly proportional to the temperature of the scattering medium.

The backscattered light is also analyzed to determine how far down the fiber it originated. Because each input pulse is 10 ns long, the interval from which the backscattered light originated will correspond directly to a specific meter-long segment of the fiber. Consequently, a log of temperature can be calculated along the length of the fiber by using only the laser source, the analyzer and a reference temperature in the surface system. There is no need for calibration points along the fiber or for calibration of the fiber before installation.

Going Against the Gradient

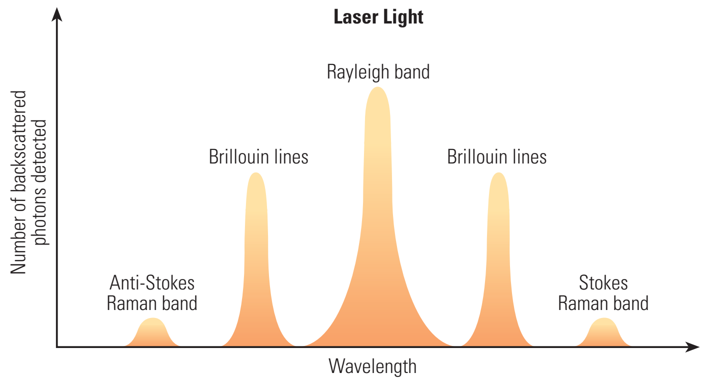
When a DTS system is initially run in the hole, geoscientists use its temperature measurements to determine a well's geothermal gradient, based on changes in temperature that occur naturally with depth. Although temperature gradients can be useful in certain well log corrections, it is not necessarily the gradient that interests most geoscientists. Rather, it is deviations from the gradient that catch their attention. From these deviations, they can infer certain characteristics about the fluids that flow from a reservoir.

The temperature profile of a well changes as fluids are withdrawn or injected. The magnitude of this change varies from one formation to another, depending on injection or production time and rate, formation permeability and thermal properties of the fluid and the rock.[3] A DTS system can monitor disturbances in thermal equilibrium over time to detect such events.

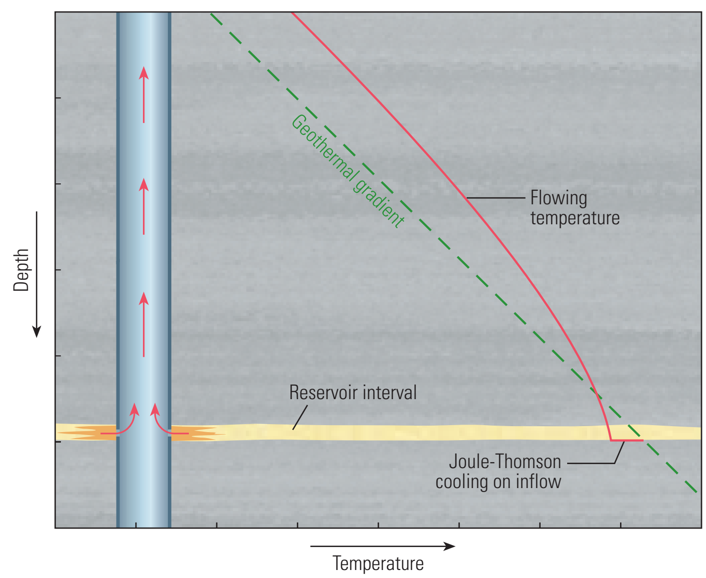
Although production or injection may initially introduce fluids of a different temperature into the wellbore, other noticeable thermal changes take place as a result of the fluid flow. These changes are explained by the Joule-Thomson effect, which is directly associated with the pressure drawdown experienced by fluids as they pass from the reservoir into the wellbore.[4] This type of temperature change occurs both when fluids flow into the wellbore, where a large pressure drop often occurs, and when they flow up the wellbore, where a more gradual pressure drop typically takes place (right).

The drop in pressure drives a corresponding change in volume of the liquid or gas, which is accompanied by a change in temperature. Through this phenomenon, it is common to see warming when oil or water enters a wellbore, or cooling when gas enters.[5] The geothermal gradient and the Joule-Thomson effect can be modeled using sophisticated nodal pressure and finite-element thermal-modeling tools, such as THERMA analysis software for wells with distributed temperature sensing.

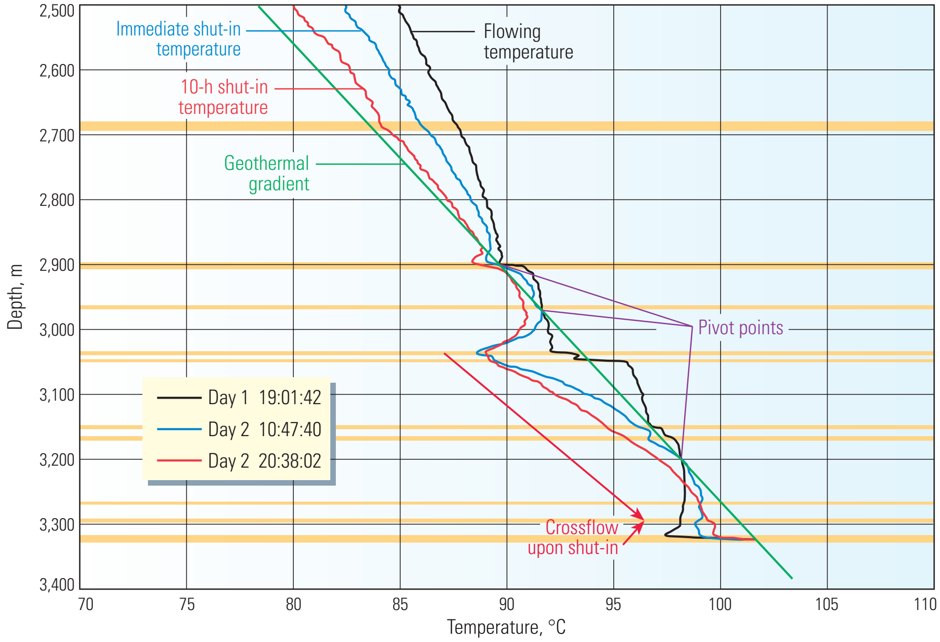
3. Brown G and Walker I: "Light Fantastic," *Middle East & Asia Reservoir Review* no. 5 (2004): 32–49. Available online at http://www.slb.com/media/services/resources/mewr/num5/light_fantastic.pdf (accessed February 18, 2009).
4. The Joule-Thomson effect accounts for the change in temperature of a fluid upon its expansion in a steady-flow process involving no heat transfer or constant enthalpy. This effect occurs in "throttling-type" processes such as adiabatic flow through a porous plug or through an expansion valve.
5. Al-Asimi et al, reference 2.



^ Backscatter spectrum. To obtain temperature measurements, the DTS system analyzes the Raman signals. The ratio of Stokes to anti-Stokes signals is proportional to the temperature.



^ Deviations from the geothermal gradient. Gas resides in a reservoir at a temperature corresponding to that of the local geothermal gradient (green dashed line). In a typical flowing well, gas will cool as it expands upon entering the wellbore, as dictated by the Joule-Thomson effect. The gas then flows up the well, exchanging heat with its surroundings by conduction through the casing (losing heat if gas temperature is above the geothermal gradient, and taking heat if its temperature is below the gradient). The resulting temperature profile is a function of the flow rate and fluid, borehole and formation thermal properties. This process continues as the gas flows up the well until the temperature curve eventually becomes parallel to the geothermal gradient.



^ DTS analysis of a flowing gas well. Deviation from the geothermal gradient (green line) is associated with fluid movement through the wellbore. DTS data were recorded while the well flowed normally (black curve) through the perforated intervals, immediately after shut-in (blue curve) and following 10 hours of shut-in (red curve). Decreases in temperature below the geothermal gradient at 3,035 and 3,320 m occur as gas flows from the reservoir and cools upon encountering a near-wellbore pressure drop, in accordance with the Joule-Thomson effect. When the well is shut in (blue curve), the relatively cold reservoir rock cools the wellbore fluid, reflecting the magnitude of the Joule-Thomson temperature effect on individual reservoir layers, which also indicates which zones have higher or lower reservoir drawdowns. Thus, after 10 hours of shut-in, instead of warming toward the geothermal line, the zone at 3,035 m remains cold (red curve), a sign that it is still producing. In fact, this zone is actually producing down the well into the zone at 3,300 m. The interval at 3,320 m also continues to flow, and its gas is also being drawn up to the zone at 3,300 m. In this manner, the data not only show which perforated intervals are flowing under normal flowing conditions, but which intervals crossflow during shut-in.

Other interesting features on this chart are the pivot points, shown where the flowing temperature curve intersects the shut-in curve. During shut-in, temperatures at most depths either warm up or cool down, but at a pivot point there is no change—indicating no heat transfer between the wellbore fluid and the reservoir. Thus, both the flowing-temperature curve and the shut-in curve are at the geothermal temperature. Identification of such points helps to define the geothermal gradient; they are the only points at the geothermal temperature irrespective of whether the well is flowing or not. This is an important and convenient tool because, under typical conditions, a well may not be shut in long enough to cool back to the actual geothermal temperature.

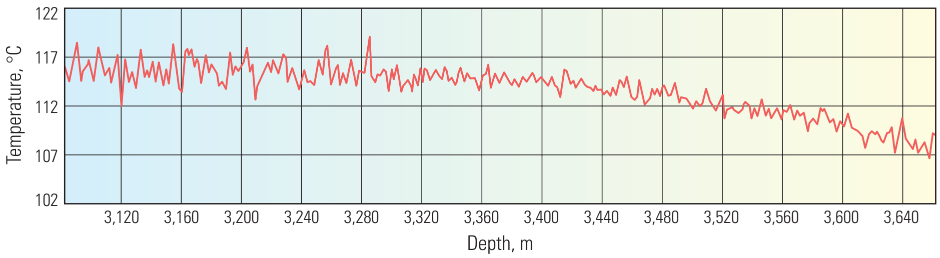
A flowing gas well illustrates the range of information that can be inferred from DTS measurements (above). Three snapshots taken during a 25-hour period allow a comparison of temperatures across multiple completion intervals. This type of comparison reveals that some zones—including the largest zone at about 2,680 m—exhibit unchanging temperatures, thus indicating they are not productive.

Distributed temperature sensing technology was used to diagnose the cause of a drop in production from a well offshore peninsular Malaysia, in the South China Sea. When Talisman Malaysia Ltd. noticed a production problem in a well at Bunga Raya field, the operator responded with a chemical treatment to remove emulsions and polymers previously left by drilling fluids.[6] Immediately following treatment, the well—an openhole completion with a slotted liner—saw production increase from 200 to 2,200 bbl/d [32 to 350 m^3/d].

However, production dropped just as dramatically within five hours of the treatment, finally stabilizing at pretreatment rates. Talisman engineers suspected that emulsions and asphaltenes had formed in the wellbore during shut-in while rigging down from the treatment. The operator needed more information on the well's formation characteristics and wellbore trajectory to understand the cause of the post-treatment production decline and to determine where and how the emulsions and asphaltenes were forming. Other concerns were how to dissolve the emulsions and asphaltenes and prevent their recurrence.

Talisman called on Schlumberger to implement a well cleanup program. An ACTive DTS temperature profile was obtained during a coiled tubing (CT) run into the hole (for more on the ACTive in-well live performance system, see "Shining a Light on Coiled Tubing," *page 24*). This

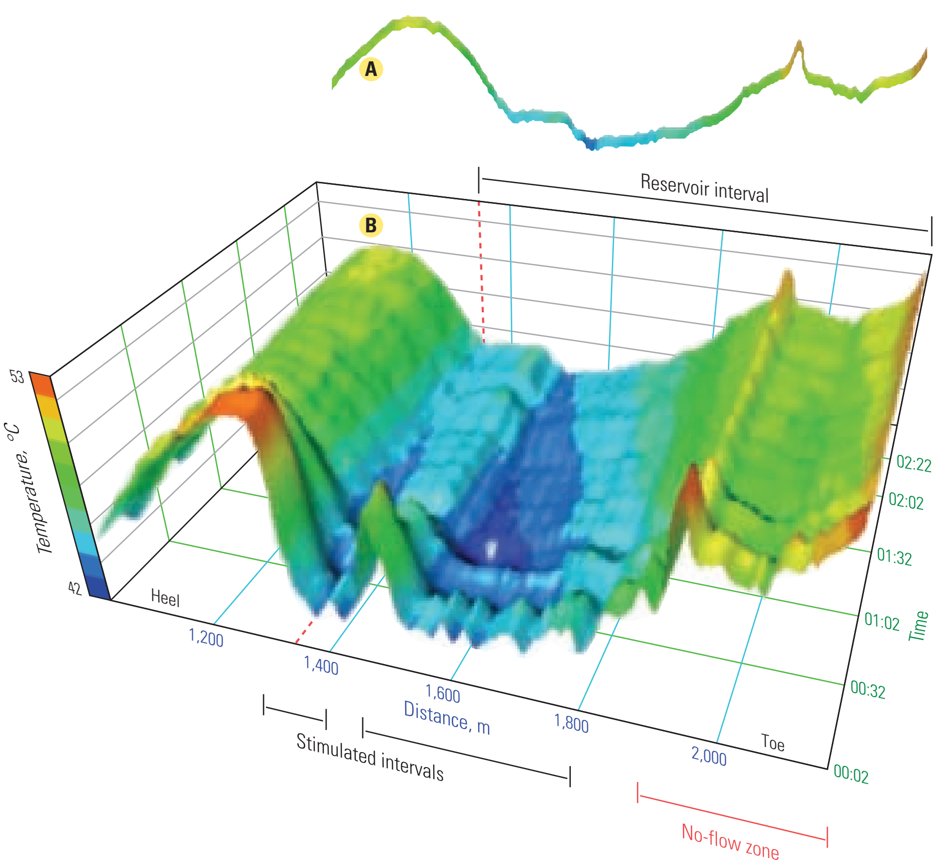
6. Parta PE, Parapat A, Burgos R, Christian J, Jamaluddin A, Rae G, Foo SK, Ghani H and Musa M: "A Successful Application of Fiber-Optic-Enabled Coiled Tubing and Distributed Temperature Sensing (DTS) Along with Pressures to Diagnose Production Decline in an Offshore Oil Well," paper SPE 121696, prepared for presentation at the SPE/ICoTA Coiled Tubing and Well Intervention Conference and Exhibition, The Woodlands, Texas, March 31–April 1, 2009.



^ DTS measurements from the Bunga Raya well. The temperature decrease from 116°C [240°F] in the heel to 107°C [225°F] in the toe was caused by cooling as a result of gas production.

survey provided a single-point temperature reading at the ACTive tool head and distributed temperature readings along the optical fiber that ran inside the CT. Using the newly acquired data, engineers selected the optimal location to collect representative bottomhole hydrocarbon samples and thus determine the best treatment interval.

DTS data indicated that the temperature had dropped across the entire interval, but was lowest at the toe (above). The temperature data, along with ACTive pressure sensor data, implied that insufficient pressure support from a nearby water injector was responsible for gas-cap expansion in this declining producer. The reason for the cooling effect was gas production from the toe section resulting from gas-cap expansion, which in turn limited liquid production. The combination of gas rates with oil and water production created a tight viscous emulsion that ultimately hindered production in this well.



^ THERMA 3D temperature tracking. DTS measurements were obtained in a horizontal gas well (A). When consecutive surveys are recorded, a 3D display can be generated (B). DTS recorded the response of the reservoir interval at 1,340 to 2,200 m, which had been stimulated by nitrogen injected through CT. Cold intervals (blue) indicate reservoir zones that have taken nitrogen at time 00:02. Over the course of the next two hours (00:32 to 02:22), the DTS data track hot and cold events caused by conduction from the reservoir as fluids move along the wellbore, thereby showing which of the stimulated intervals are flowing. The data identify two major intervals where the treatment was successful and reveal that the toe of the well was not stimulated sufficiently to flow.

Adding Another Dimension

Advances in DTS are providing operators with a choice of permanent or temporary wellbore-temperature sensor systems. When installed as a permanent component of a completion system, the DTS monitoring system supplies valuable temperature data in real time, allowing operators to respond quickly to changes in production. During workovers or other interventions, a DTS system can be run into a wellbore by slickline or inside coiled tubing; at the end of the job, the optical fiber is retrieved from the well.

A thin, flexible steel tube protects and houses the optical fiber, enabling the glass fiber to snake along the wellbore trajectory. This capability permits geoscientists to precisely locate and plot the position of downhole thermal events. Such data are valuable in their own right. However, by taking a series of temperature surveys over a given period, a geoscientist can compile a 3D display to track the progression of a thermal event in space and time (below left). Specialized programs such as THERMA modeling and analysis software for wells with distributed temperature sensing can be used to load multiple temperature traces and assess well performance. Viewing the DTS data as a series of traces allows time-based properties of the well's performance to be identified in production, injection and acid stimulation applications.

Advances in fiber technology are also helping to expand the range of DTS applications. Distributed temperature sensing systems are now being installed in heavy-oil thermal-recovery wells in Canada. These wells, known as steam-assisted gravity drainage (SAGD) wells, are inhospitable to fiber-optic systems. Most optical fibers degrade when exposed to the levels of hydrogen found in these heavy-oil wells. The rate of degradation accelerates at high temperatures typical of SAGD wells, and this impairment can eventually prevent the transmission of laser pulses through the fiber. With the development of WellWatcher BriteBlue optical fiber for harsh environments, DTS systems are better able to withstand heat and resist hydrogen degradation. The downhole data acquired with these permanently installed fibers help operators evaluate SAGD steam-chamber profiles to gain a better understanding of the steam-injection process. This knowledge is helping operators extend the life of wells and increase overall hydrocarbon recovery. —MV