Real-Time Fiber-Optic Distributed Temperature Sensing: Oilfield Applications

Reservoir-performance monitoring can provide real-time information for more-timely operating decisions. Often, the data can be collected without performing an intervention. One reservoir-monitoring technique is fiber-optic distributed temperature sensing (DTS). DTS can provide a temperature profile of the entire wellbore in real time, which, in turn, can provide an enhanced understanding of the downhole flow (or injection) profile.

Introduction

DTS can measure temperature distribution along a fiber-optic line. The optical fiber comprises concentric layers of materials—the core and the cladding. The core is the light-carrying element. The surrounding cladding provides the lower refractive index that enables total internal reflection of light through the core. The back-scattered light from the fiber-optic line provides information about the temperature from where the reflection originated.

Installations. The most common installation uses a retrievable fiber rod or stem deployed from the surface into preinstalled capillary tubing clamped onto the production tubing. When production stabilizes, the fiber (in the form of a flexible rod or stem) is inserted into the capillary tubing and the surface equipment is connected to the fiber. Data are recorded continuously from the start to obtain the baseline profile and profles during the cooling-down period (when cold water is pumped through the tubing/casing annulus) and throughout the production period. This method facilitates retrieval of the fiber-optic sensing device (fiber stem) upon completion of the survey so that it can be used in another survey. This procedure provides temperature data at a relatively low cost and within a short time frame.

A second method uses a 0.156-in.-outside-diameter steel tube with preinstalled multimode fiber material. The physical dimension of the fiber is a 50-µm core surrounded by a 125-µm cladding or jacket. The preinstalled-fiber tube can perform a retrievable survey in production wells with open-ended tubing and pressure equipment. As with wireline, the fiber tube is spooled back onto a cable drum and is moved from one location to another as required. The retrievable fiber tube also is used for surveys in observation wells.

A third method is fiber pumping. Fiber-optic material is pumped into preinstalled capillary tubing. A check valve installed below the capillary tubing allows pumping the fiber through the capillary tubing as a semipermanent or permanent (cemented in place with casing) system, either single-ended or double-ended. In this type of installation, the fiber is left in place after it is pumped. This method is used for wells where other methods cannot be applied.

Fiber-optic technology provides accurate monitoring in high-temperature/high-pressure applications and offers equipment integrity and operational simplicity. With the allocation of proper acquisition time, a resolution of 0.3°F can be achieved with temperatures as high as 575°F. The surface equipment pulses laser signals at very high rates into the fiber. The reflected pulses train on the same fiber and are captured and analyzed to derive temperature information. Accurate and precise information on temperature, therefore, can be assessed along the fiber. Current technology enables use of fiber-optic cables as long as 15 km.

Field Applications

Case History 1: Horizontal-Well Flow Profiling. The operator wanted to acquire qualitative information concerning the fluid-contributing sections of the horizontal wellbore. The well was drilled into the lateral section to the producing sand body at a depth of 787 ft true vertical depth subsea (TVDSS). The overlaying sand body was estimated to be at 742 TVDSS. The original pressure of 420 psi had depleted to 190 psi and the well was expected to have a high gas/oil ratio. The upper gas-bearing sand was suspected to be channeling into the lower sand from a nearby horizontal well. The cement-evaluation log showed poor bonding; therefore, remedial cementation was undertaken to improve the bond. The oil/water contact was not seen in the horizontal section. Before the workover, production had declined from 820 to 444 BFPD, with a significant increase in the water cut from 35 to 50%. This change was observed within just 2 weeks.

Fiber-Optic Installation and Results. The fiber-optic cable was installed along the entire length of the wellbore from wellhead to total depth by physically attaching the preinstalled-fiber tube to the production tubing. The baseline pass showed a geothermal-gradient maximum temperature of 130°F in the horizontal section.

A magnetic-resonance-imaging log recorded in an offset well indicated

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that the permeability in the sand varied from 150 to 50 md, from the sand heel to toe. In expectation of a similar permeability profile, an injectivity test was performed to confirm the permeability distribution across the sand. During the cooling test, it was clear that the injection fluid reached out to 1,750 ft. At a further distance, no variation in temperature was observed, indicating that no fluid, or only a negligible amount, had been injected beyond 1,800 ft.

Following injection, the well was shut in. After approximately 1 hour, the electrical submersible pump (ESP) was switched on, and the well was put on production. Wellhead pressure stabilized at 60 psi after 1 hour of production. Temperature-profile tests at 1 hour, 3 hours, and 12 days were inconclusive regarding fluid entry. After approximately 1 year, another survey was performed. Analysis showed all production coming from the heel of the horizontal section.

Value Created. This test was an attempt to assess the flow contribution from the horizontal section, as well as other temperature changes in the wellbore. The system is still in place, and data are still providing real-time temperature profiles for assessing the production contribution.

The DTS survey provided real-time temperature data that would have been difficult to acquire by other means. The ESP heating shown in the temperature profile during production provides additional information on pump- and motor-operating conditions. This information was used to improve the ESP design and to optimize production. The change in temperature-profile gradient provided information on the fluid column in the annulus. This information (fluid above pump) could be used to set the depth of ESP accurately for future workovers to optimize fluid production.

Case Study 2: Minifrac Height Monitoring. The operator wanted to obtain real-time temperature data during a hydraulic-fracturing treatment (breakdown, step rate, and minifrac operation) to estimate the height and extension of the fracture. Fiber-optic cable was run in the hole with an appropriate weight bar to total depth. Temperature data were recorded during the entire operation.

Normally, fracture extensions are contained within the sand being fractured when the sand is between two thick impermeable zones, such as shale breaks. In this situation, the fracture was limited to the sand, and the objective was achieved. When such boundaries are absent, the fracture grows both upward and downward. Monitoring real-time temperature gives an advantage when cold fracturing fluid migrates both upward and downward and shows a cooling effect.

The cooling phenomenon depends on the amount of fluid. Small channels through the cement sheath and through the formation cool off very fast and cannot be captured with conventional wireline temperature tests. The fiber tube across the zone can capture these small changes. The cooling effect above the perforations extended upward. But some of the cooling disappeared during shut-in condition, which identified areas in which the fluid did not penetrate. Analysis indicated that the treatment went into the perforations, with no height growth seen from the continuous temperature profile.

Case History 3: Breakthrough in an Oil Well. Because of low reservoir pressure, this well was completed with a tubing pump. Therefore, it was virtually impossible to perform a flowing production log with conventional production-logging tools. To obtain a quantitative production log, capillary tubing was installed on the production tubing during a planned workover and extended across the producing interval. To perform the survey, a semirigid fiber cable was inserted temporarily into the capillary tubing.

Flowing-Temperature Analysis. The heating effect of the pump operation was seen clearly in the flowing and in the shut-in surveys. The dynamic fluid level was difficult to determine. By considering the character or shape of the flowing-temperature curves, the fluid level appeared to be at 520 ft TVDSS. Above 520 ft TVDSS, the flowing-temperature-curve difference increases.

Shut-in Temperature Analysis: Location of Fluid Levels. The annulus fluid level (AFL) should remain at essentially the same depth after a few hours of shut-in. Above the AFL, the temperature returned to the geothermal gradient more quickly than below the AFL, where the temperature return exhibited delay. However, assuming the fluids are static in the annulus, there should be gas in the upper section and liquid in the lower section. Therefore, the lower-section temperature should return to the geothermal temperature faster and should remain cooler than the upper section. Temperature across the air/liquid interface in the annulus should be the opposite of that observed. It was concluded that something increased the temperature below the liquid level, and that the well should be flowing. It was determined that the AFL was changing as a result of a casing leak. Also, it was determined that the well was flowing upward from 700 to 420 ft TVDSS during shut-in periods. The 24-hour shut-in temperature was cooler than the geothermal gradient in the 700- to 760-ft TVDSS zone resembling injection from the top of the perforated interval to the middle perforated interval at 760 ft. The shut-in temperature was hotter than the geothermal temperature from 800 ft up to 760 ft TVDSS, indicating production from this section. The zone at 760 ft TVDSS should be a low-pressure interval, compared with the top and the bottom sections of the perforated interval.

Flow-Rate Simulation From the Temperature Data and Surface Data. The 8-hour flowing profile was selected to perform flow-rate calculations because it was considered most representative of the long-term flow conditions. The measured-flow profile and thermal-flow-simulator model-output temperatures showed an excellent fit. An increased temperature anomaly existed at the top of the perforated intervals caused by the pump generating heat during operation. For this simulation, it was assumed that no thermal interaction existed between the zone of interest and the upper heated zone by the pump operation.

Because all the sands were perforated, the most prospective zones were selected from the available openhole logs and used as input to the thermal-flow simulator model. The pay zones from 692 to 710 ft produced 95% of the total flow, according to the thermal-flow simulator-profile analysis. Therefore, this high-permeability/high-pressure zone should be the main source of produced water, between 100 and 97.3% water cut. The remaining producing zones' cumulative water cut, therefore, must be between 48 and 100%. **JPT**