Production Logging Principles

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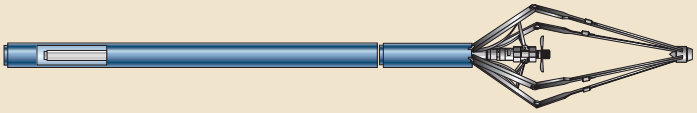
The term *production logging* covers a wide array of sensors, measurements and interpretation techniques. Operators use production logs to evaluate fluid movement in and out of wellbores, quantify flow rates and determine fluid properties at downhole conditions. Completion engineers can evaluate production and perforation efficiency and plan remediation or modify future completion designs based on the interpretation of production logs. Reservoir and production engineers can use these logs to help manage and optimize well and reservoir performance.

Production logging traces its origin to the 1930s and the measurement of wellbore temperature. Over the decades, other measurements—including pressure, fluid density, flow velocity and *holdup* (volume fraction of pipe occupied by fluid)—have been added to the service. Although measurements of pressure, temperature and flow rate can be obtained at the surface, surface measurements do not necessarily reflect what is happening in the reservoir. Comprehensive production log evaluation requires that measurements be acquired downhole.

Production Logging Measurements

Production logging consists of several measurements, many of which are used in a complementary capacity to determine fluid and flow properties (below). Fluid velocity is commonly measured with a spinner flowmeter—a rotating blade that turns when fluid moves past it. In ideal conditions, the rotational speed of the blade in revolutions per second (RPS) is proportional to the fluid velocity. Friction in the spinner bearings and effects from fluid viscosity result in nonlinear velocity responses, requiring calibration of the measurement. This calibration is accomplished by making upward and downward passes at varying logging speeds. Before absolute fluid velocity is computed, spinner speed is corrected for relative tool speed. Because of friction near the pipe wall, absolute fluid velocity is not the same as the average velocity of fluid moving through the pipe. After applying correction factors, engineers convert the spinner velocity to an average velocity using computer modeling techniques, which present the fluid velocity profile across the pipe diameter.



^ Production logging toolstring. This production logging toolstring consists of a fullbore spinner, fluid holdup and bubble count probes, a pipe diameter caliper and centralizer, a relative bearing sensor, pressure gauges, a temperature sensor, a gamma ray tool and a casing collar locator. When engineers run the tool in memory mode, batteries and a data recorder are used. Surface readout tools use a telemetry and power section.

Pressure is a versatile measurement with several applications for reservoir and production engineers. Strain, sapphire and quartz gauges are the main devices used to measure pressure. Engineers may also measure pressure using a *manometer*—a device that converts mechanical displacement to pressure. From wellbore pressure data, engineers can determine well stability at the time of logging, estimate reservoir pressure from multirate logging surveys, calculate fluid density and obtain key reservoir parameters by performing transient rate analyses.

Temperature is an integral measurement for all production logging. Engineers use temperature data to make qualitative conclusions about fluid entries, particularly in low–flow rate scenarios in which a spinner may not be sensitive enough to detect movement. Gas entries create cooling anomalies that are easily detected using temperature logs. Temperature measurements are also used in fracture treatment evaluation and to evaluate injection well performance. Using temperature data, engineers may be able to evaluate the integrity of well completions, detect casing leaks and identify flow through channels behind pipe. Resistance temperature detectors, the most common type of sensor, usually consist of a platinum wire or film deposited on a nonconductive surface. Changes in temperature cause variations in resistance, which is calibrated and converted to temperature.

Fluid density measurements differentiate oil, gas and water. Service companies have developed tools based on a variety of physical principles to obtain fluid density measurements:

- differential pressure across two ports separated by a known distance
- Compton scattering of gamma rays
- pressure gradient relation to density
- flow vibration relation to density and viscosity.

In the case of two-phase flow, engineers can use fluid density—in conjunction with other measurements such as fluid viscosity—to compute holdup. Where multiphase flow is present, they must employ tools with probes distributed across a wellbore to directly measure the fluid holdup. One type of tool senses differences in optical reflectance to obtain holdup, which involves measuring the amount of light reflected back from a fluid. Another type of tool differentiates water from oil and gas using probes that measure electrical properties of the fluids.

Auxiliary measurements commonly acquired by production logging strings are casing collar logs, gamma ray logs, caliper and deviation. Casing collar and gamma ray logs provide depth control and correlation with completion components. Caliper and deviation data are used in production modeling programs.

Production logs can be difficult to interpret because fluid flow may not be uniform, and multiple passes result in large amounts of data, some of which may produce conflicting answers. Computer programs have been developed to assist engineers in understanding downhole conditions; computer-generated interpretations remove some of the

Oilfield Review Autumn 2013: 25, no. 3.
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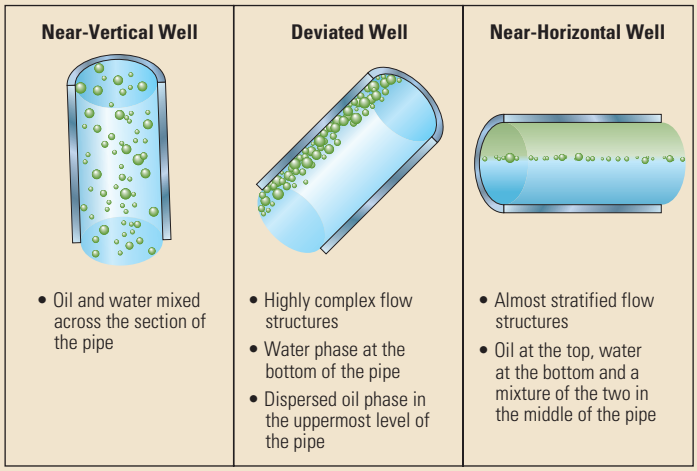
ambiguities associated with the interpretation process (below). The interpretation product can often help the engineer identify more-productive intervals, detect water entry and determine intervals that do not contribute to production.

Flow Regimes

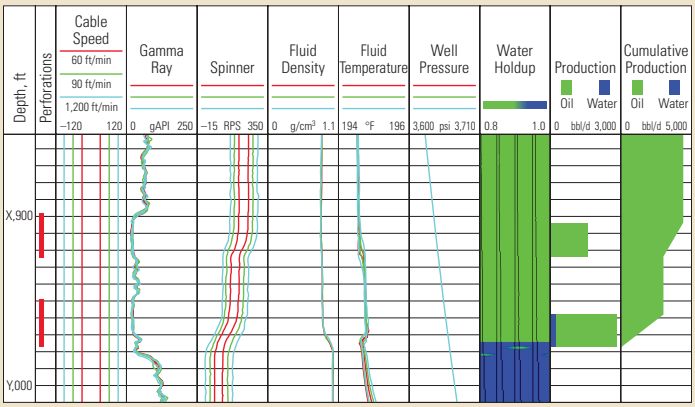
To analyze production logging data, production engineers must be aware of downhole flow regimes. Knowledge of expected flow regimes allows operators to choose measurements suitable for the downhole conditions.

Single-phase flow—when only oil, gas or water is produced—is the simplest flow to evaluate; however, it is uncommon in most wells. *Two-* and *three-phase flow*—mixtures of two or three fluid types—can exhibit a wide variety of flow regimes and are complicated by deviated wellbores (right). In such cases, gravity ensures that the lighter phase travels at a higher velocity than the denser phases. The velocity difference between the different fluids is the *slip velocity*.

As fluids migrate uphole, the flow regime usually changes. For instance, oil with dissolved gas can enter the wellbore as a single phase. The hydrostatic pressure decreases as the oil rises, and gas bubbles begin to form in the oil. The flow regime is then *bubble flow*. Pressure is further reduced as the mixture moves uphole; more bubbles form and smaller bubbles aggregate to create larger bubbles. Large bubbles, or *gas slugs*, travel faster than both small bubbles and liquids. Gas slugs may initiate *slug flow*. Slugs tend to unite and move to the center of the pipe, forcing most of the oil to flow along the pipe walls. This flow regime is called *froth flow*. Eventually, a *mist flow* regime may be reached, in which the gas is carrying droplets of oil, and both fluids are traveling at essentially the same velocity. This simplified example becomes complex in deviated wellbores or when fluids of various phases enter the wellbore from multiple zones. Modeling programs attempt to resolve these complexities using production log data.



^ Fluid flow. Theoretical work and flow loop experiments have helped engineers understand multiphase flow in vertical, deviated and horizontal wellbores. The parameters of interest include pipe diameter and inclination and fluid density, viscosity and flow rate. Each case shows the variation in water and oil holdup based on well deviation.



^ Production log. This log shows data typically provided by downhole sensors in a production logging survey. Two intervals have open perforations (Track 1, red). Engineers make multiple passes at different logging speeds (Track 2); negative cable speeds represent down passes and positive logging speeds are up passes. Color-coding based on logging speed helps differentiate datasets. Gamma ray data (Track 3) provide correlation with openhole logs. From spinner data (Track 4), engineers identify changes in fluid velocity associated with inflow from production, outflow from thief zones or outflow from injection. The fluid density data (Track 5) indicate water (1.0 g/cm^3) below the perforations (the sump), which then transitions to mainly oil (0.75 g/cm^3). Temperature data (Track 6) indicate heating or cooling effects caused by inflow of fluids. Steady well pressure (Track 7) is a characteristic of stable flow during acquisition. Holdup data (Track 8) indicate water and oil fraction within the wellbore. The software computes incremental and cumulative flow rates (Tracks 9 and 10). The two intervals are producing oil; the lower interval is also producing a trace amount of water (Track 9).

Reservoir Surveillance and Management

Production logs help engineers diagnose problems that occur during the life of a single well and are also used for management and surveillance of multiple wells or of the entire reservoir. A common challenge faced by operators in mature fields is identifying zones that produce excessive amounts of water. Produced water impacts surface handling operations because water must be separated from the flow stream for disposal. Produced water may also affect well performance by limiting the volume of hydrocarbons being produced. After identifying water-producing zones, production engineers may perform remediation to reduce or eliminate water production.

Operators may also use production logs to calibrate reservoir simulation models. During full-field reservoir model history-matching, engineers can use production log data to help identify or match zonal contributions, fine-tune parameters and align the model with the empirical performance data.

Lifetime Logging

Production logs provide reservoir and production engineers with a diagnostic aid for understanding the downhole wellbore environment. These in situ measurements acquired under dynamic conditions are a snapshot of the existing situation. But that snapshot captures the situation only for that moment in time. Whether by fluid extraction or injection, oil and gas production changes reservoir conditions. Production logs help operators understand well and reservoir dynamics over the life of a well and create a roadmap for future remediation, production enhancements and reservoir development programs.