Flow Scanner

Production logging in multiphase horizontal wells
Applications

- Multiphase flow profiling in nonvertical wells
- Identification of fluid and gas entries in multiphase well or liquid in gas wells
- Detection of fluid recirculation
- Stand-alone, real-time, three-phase flow interpretation

Benefits

- Unambiguous flow profiling in nonvertical wells regardless of phase mixing or recirculation
- More accurate flow measurements than possible with conventional logging tools in highly deviated and horizontal wells
- Three-phase flow rates computed in real time using dedicated algorithms

Features

- All sensor measurements simultaneous and at the same depth
- Combilable with PS Platform* and other cased hole logging tools
- Short length for running in wells with high dogleg severity
- Direct, localized measurements of phase velocities and calculation of a multiphase velocity profile
- Full three-phase holdup answer from the same depth
- Scanning sensors across the vertical axis for more accurate detection of phase interfaces
- Measurement of mixed and segregated flow regimes
- Independent measurement of gas velocity in multiphase horizontal wells
- Detection of heavy phase recirculation downhole
- Software optimization and real-time display of data from all 19 sensors
- Caliper and relative-bearing measurements for continuous sensor location

Multiphase fluid dynamics

In vertical wells and wells with deviation less than 20°, oil and water are mixed across the entire wellbore, with oil, the lighter phase, increasing on the upper side of the well. The velocity profile is smooth, and the water holdup profile varies gradually across the pipe. Averaged measurements across the wellbore are adequate to determine the velocity and holdup with this type of flow structure.

Once deviation exceeds 20°, however, the center measurements of conventional production logging tools are usually inadequate for multiphase flow profiling.

For wells with deviation between 20° and 85°, some portions of the wellbore have monophasic flow, but the overall flow structure is complex. Water, the heaviest phase, segregates to the bottom of the pipe, and the mixing layer is on the upper side of the hole with dispersed bubbles of oil.

Water is frequently recirculated at low flow rates, and the water velocity on the lower side of the hole can be negative in some areas. At high flow rates, differential acceleration of phases caused by the shear forces between the different fluids can lead to instabilities in the flow structure. This flow structure has large gradients in the velocity and holdup profiles.

Oil and water flows in wells with deviations between 85° and 95° are predominantly stratified. Water flows at the bottom with oil on the top. Even for flow rates as high as 20,000 B/D in a 5-in. [127-mm] liner, there is little mixing. At low flow rates, the flow has a strong dependence on well deviation.

When gas is also present, depending on the well deviation, as many as six major flow regimes can be encountered. For a constant flow rate, the holdup and velocity profile of each phase vary with the well deviation.

Biphasic experiments carried out in a controlled flow loop with equal flow rates for oil and water show the dramatic effects of borehole deviation on flow behavior.
At 90° the velocities and holdups of oil and water are nearly equal. Because oil is more viscous than water, it has a slightly lower velocity. The oil holdup is slightly higher than the water holdup.

As soon as the borehole deviates slightly from 90°, the oil and water flow at different velocities. At high flow rates the dependence on borehole deviation is smaller because the increasing shear frictional forces against the wall and interface dominate.

At deviation lower than 90° (uphill), water, the heavier phase, slows down, and oil velocity increases. The water holdup increases while the oil holdup decreases. Any gas present would start to slug.

At well deviation above 90° (downhill), flow is still predominantly stratified. The water flows much faster than the oil because of its higher fluid density. The water holdup now decreases while the oil holdup increases.

**Why conventional production logging technology is inadequate in nonvertical wells**

Using production logging to accurately determine the inflow of oil, gas, and water phases is fundamental to developing optimum production strategies and designing remedial workovers. But in highly deviated wells conventional production logging tools deliver less-than-optimal results because they were developed for vertical or near-vertical wells.

Downhole flow regimes in deviated boreholes can be complex and can include stratification, misting, and recirculation. Segregation, small changes in well inclination, and the flow regime influence the flow profile. Logging problems typically occur when conventional tools run in deviated wells encounter top-side bubbly flow, heavy phase recirculation, or stratified layers traveling at different speeds.

Flow loop studies have also revealed the ineffectiveness of conventional logging tools in multiphase flows. Center measurements made by such tools are inadequate for describing complex flow because the most important information is located along the vertical diameter of the wellbore. Conventional tools have sensors spread out over long distances in the wellbore, making measurement of complex flow regimes even more difficult.
The solution: Flow Scanner system

The Flow Scanner* horizontal and deviated well production logging system was developed especially for highly deviated and horizontal to near-horizontal wells.

On one side of the tool’s retractable arm are four miniature spinners designed to measure the well fluid-velocity profile. On the other side are arrays of five electrical and five optical probes for measuring localized water and gas holdups, respectively. Additionally, a fifth miniature spinner and a sixth pair of electrical and optical probes on the tool body measure flow properties on the low side of the well. All sensor measurements are made at the same depth simultaneously.

The Flow Scanner system is run eccentric, lying on the low side of the well with its arm deployed across the vertical diameter of the wellbore. The arm is extended to a length equal to the diameter of the production tubulars, so it serves as a caliper, providing the area measurements needed to calculate flow rates.

The tool has a small outside diameter (OD) of 1 1/16 in. [42.9 mm], and it can be run in holes ranging from 2 1/2 in. to 9 in. [73.0 to 228.6 mm] using coiled tubing, wireline, or the MaxTRAC* well tractor system. Its short 16-ft [4.9-m] length makes it ideal for wells with high dogleg severity. When an even shorter toolstring is desired, the 4-ft [1.2-m] hydraulic section used for scanning and closing the tool can be removed. The system operates in temperatures to 302°F [150°C] and at pressures to 15,000 psi [103,425 kPa].

The Flow Scanner system is combinable with the PS Platform system and other cased hole logging tools.

Multiphase velocity profiling

Because the Flow Scanner tool measures the velocity profile along the vertical diameter of the wellbore, it can measure velocity variations that cannot be detected using a single, centered spinner. It provides measurements of mixed and segregated flow regimes, including direct independent measurement of gas velocity in a multiphase horizontal well. The Flow Scanner tool even detects water recirculation downhole.
Each of the five miniature spinners makes a direct, localized measurement of the velocity of the fluid passing through it, enabling calculation of a multiphase velocity profile.

**Distinguishing hydrocarbons from water**
The Flow Scanner system detects water by using six low-frequency probes that measure fluid impedance. Because water conducts electric current, whereas oil and gas do not, a threshold is set that allows the tool to distinguish oil and gas from water.

Each probe generates a binary signal when oil or gas bubbles in a water-continuous phase, or droplets of water in a hydrocarbon-continuous phase, touch the probe’s tip. Water holdup is determined by the fraction of time a probe’s tip is conducting, and the water holdup profile accurately represents the flow regime in the wellbore.

This methodology enables a local water holdup measurement, independent of fluid properties, without any need for calibrations. Conventional tools, on the other hand, require accurate calibration in oil and water. Furthermore the bubble count measurement—the log that represents the number of nonconducting events detected during a monitoring interval—can be used to locate fluid entries. Conventional tools also lack the accuracy to do this.

**Distinguishing gas from liquids**
Conventional low-frequency probes can only distinguish water from hydrocarbons, but the Flow Scanner system is also equipped with optical probes for gas detection.

Its six GHOST* Gas Holdup Optical Sensor Tools are sensitive to the fluid optical refractive index. Typically gas has an index near 1, water near 1.35, and crude oil near 1.5. Because oil and water have very similar fluid indices, the optical probes are used to distinguish gas from liquid.

The gas bubble count can also be obtained from the raw data and used to locate first gas entries. Optical probes allow a local gas holdup measurement without requiring calibration because their signals are binary.

Together, the optical and electrical probes deliver a full three-phase holdup answer from the same depth interval.

**Flow Scanner monitor box**
Flow Scanner software optimizes and displays the data sent uphole from the spinners and probes. Two views are constantly updated with real-time acquisition data.

One view shows relative fluid velocities measured by the spinner array, while the other shows phase distribution across the pipe section. For both views, the pipe is sliced horizontally into the five layers associated with the different combinations of spinner, electrical-probe, and optical-probe measurements.

In the spinner view, five rectangles are plotted with lengths proportional to the rotational velocities of the corresponding spinners. Each rectangle is divided into color-coded sections with widths proportional to the three phase holdups seen by the electrical and optical probes.

In the cross-sectional view, each layer is color coded to represent the phase with the highest holdup seen by the probes. The holdup values of the two remaining phases are represented by proportionate numbers and sizes of bubbles. The relative positions of the sensors are also shown, with circles for the spinners and dots for the probes.
Case study: Gulf of Suez

Aging reservoirs in the Gulf of Suez produce viscous oils at high water cuts through deviated to horizontal completions. Conventional production logging tools often have difficulty defining the complicated flow regimes and identifying areas for water shutoff to maximize oil recovery as a field nears its economic limit.

One well with an inclination of 37° was producing with gas lift through six open intervals. Production was 2,058 B/D with 97% water cut. When a conventional production logging survey was unable to evaluate individual interval contributions or identify sources of water production, the Flow Scanner tool was deployed on wireline.

The figure compares logs from the Flow Scanner and conventional production logging surveys. The Flow Scanner flow profile shows that approximately 25% of the oil and 85% of the water were being produced from perforations below X400 ft. The remainder of the water and some oil were produced from perforations at X390 ft. The two perforations above X390 ft were producing clean oil, and more than half of the oil was flowing into the top perforation.

Conventional production logging sensors could not detect oil entering the top perforations because the spinner was affected by water recirculation, and the resolution of the gradiomanometer was too low for it resolve oil contributions. The conventional survey erroneously attributed 90% of the oil production to the lower perforations.

On the basis of the Flow Scanner results, a workover operation was planned to optimize the oil production. After cross-referencing the log results with geologic information on the location of a sealing layer of shale, the operator set a plug at X400 ft to isolate the majority of the high water-cut zones in the bottom of the well.

The resulting production of 556 BOPD and 2,532 BWPD represented an 800% increase in oil production, and payback was accomplished in less than a week.

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The Flow Scanner system identified and quantified zonal oil and water production in this well in the Gulf of Suez after conventional production logging had failed. A workover operation led to an 800% increase in oil production.

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Case study: North Sea

The Flow Scanner system was run in a North Sea well on coiled tubing. The well was producing 9,800 BOPD, with 20% water cut and no gas, through a 4½-in. [114-mm] liner. Maximum deviation over the 2,300-ft [700-m] interval is 93°.

In the flow profile shown in Track 1 both oil and water were produced from the lowest perforations in the well, but the major inflow of oil was at X680 m. Production increased significantly closer to the heel of the well.

The holdup profile in Track 2 shows the effect deviation has in horizontal wells. Holdup varies greatly when flow rates are low, and it lessens as flow rate increases, eventually reaching a point at which deviation has almost no effect. This proves the flow-loop tests are representative of actual conditions downhole.
Case study: Middle East

A client in the Middle East wanted to test the Flow Scanner system in a well considered to be single phase. The 52° deviated well was producing 3,300 BOPD, with no water. The Flow Scanner system was run on wireline and recorded the field log shown in the figure.

The relative bearing measurement (purple) in Track 1 shows that the tool kept its sensors deployed across the vertical axis with only slight movement and remained within 10° throughout the pass.

Track 2 shows the holdup of each phase in the well. It clearly shows water to 100 ft below the surface.

Track 3 is a velocity image. Negative velocity (recirculation) is shown in yellow, then orange, and red as it increases; increasing positive velocity (production) is shown in blue, then green, and dark green. Oil is being produced in the middle and on the high side of the well, while water is recirculating on the low side of the well (left). Recirculation could be seen to 100 ft below the surface.

Tracks 4 and 5 represent the water flow rate (negative) and the oil flow rate (positive) calculated using the default pitches for all five spinners.

Tracks 6 and 7 show the gamma ray, pressure, and temperature curves recorded with the PS Platform basic measurements sonde.

This Middle East well was producing 3,300 BOPD with 0% water cut. Holdup measurements show water to 100 ft below the surface, and the velocity image shows that the water is recirculating.
### Flow Scanner Specifications

<table>
<thead>
<tr>
<th>Specification</th>
<th>Unit 1</th>
<th>Unit 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>OD (in. [mm])</td>
<td>1.668</td>
<td>42.9</td>
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<tr>
<td>Length† (ft [m])</td>
<td>16.0</td>
<td>4.9</td>
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<tr>
<td>Weight (lbm [kg])</td>
<td>108</td>
<td>49</td>
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<tr>
<td>Temperature (°F [°C])</td>
<td>302</td>
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<tr>
<td>Pressure (psi [kPa])</td>
<td>15,000</td>
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<td>Corrosion resistance</td>
<td>NACE Standard MR0175</td>
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<tr>
<td>Borehole coverage</td>
<td>90% in 6-in. ID</td>
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<tr>
<td>Three-phase holdup accuracy</td>
<td>±10%</td>
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<tr>
<td>Velocity accuracy</td>
<td>±10%</td>
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<tr>
<td>Hole size (in. [mm])</td>
<td>2.875 to 9 (73.0 to 228.6)</td>
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<tr>
<td>Min. restriction (in. [mm])</td>
<td>1.813</td>
<td>46.0</td>
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</tbody>
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†Flow Scanner tool only. Basic measurement sonde and head add 10.2 ft [3.1 m]. An eccentralizer and swivel are also recommended in deviated wells.