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Wireline sensor expands capabilities of DFA

Analysis tool enables downhole measurement of *in situ* viscosity in real time.

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Downhole fluid analysis (DFA) is a critical aspect of well development, delivering a wealth of data operators use to identify reservoir properties that lead to a better understanding of a field's petroleum system and, ultimately, commercial viability. Over the years DFA has evolved to include real-time *in situ* sensors placed in the well with wireline formation tester (WFT) tools to measure key reservoir fluid characteristics, including hydrocarbon composition, gas-oil ratio (GOR), CO_2, downhole fluorescence, water pH and density.

Conventional methods of obtaining formation fluid viscosity include laboratory analysis at surface and pressure-volume-temperature (PVT) correlations, which are limited by quantity, uncertainty and time as the data may not be available for several weeks or months. Surface viscosity measurements also can be affected by irreversible alteration of the sampled fluid through pressure and temperature changes and by the effects of long-term sample storage.

The capabilities of DFA have recently been expanded to include a real-time wireline method for measuring formation fluid viscosity, an important parameter that influences fluid mobility, which is directly related to productivity and fluid displacement. By understanding the viscosity of downhole fluids, operators can more

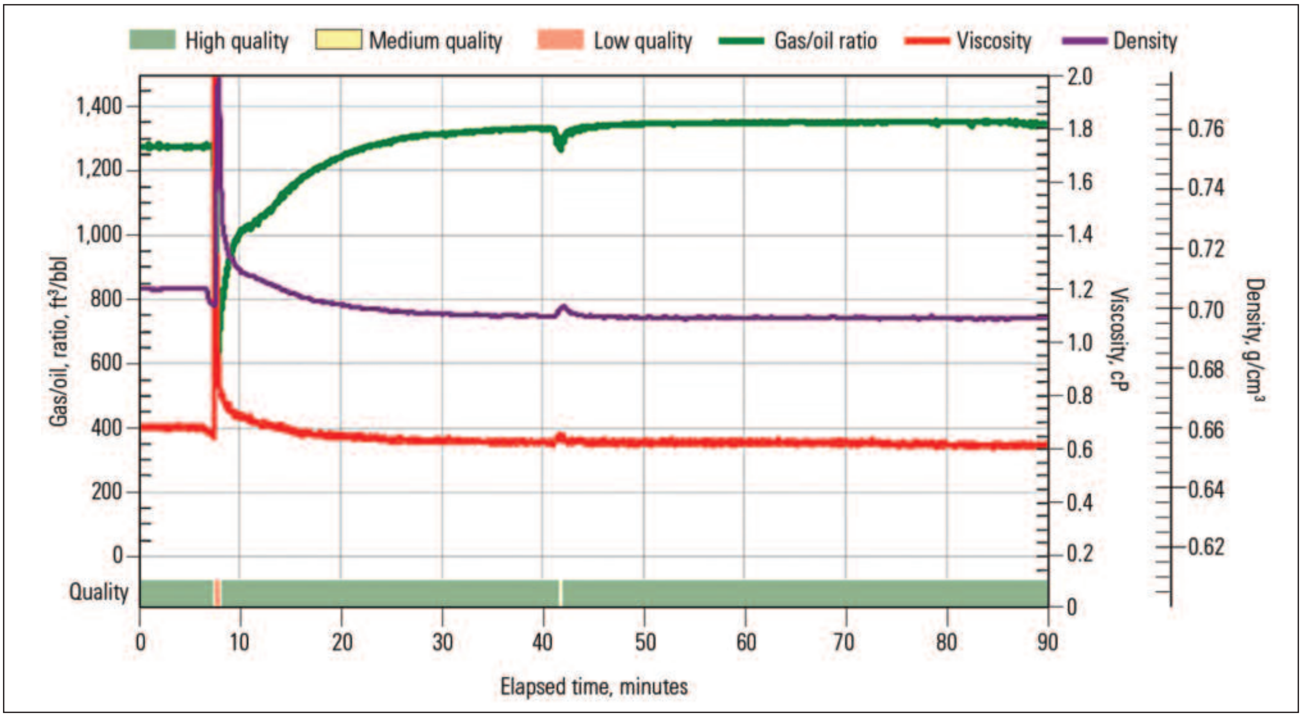

FIGURE 1. A DFA plot from one of the tested stations shows *in situ* fluid analysis results, including viscosities from vibrating wire (red), resonant rod density (purple) and GOR (green). There is no noise affecting the measurement as observed from the smooth viscosity curves and the vibrating wire quality flag. (Source: Schlumberger)

DFA / LAB	Depth, ft	GOR, ft^3/bbl	C_1 wt%	C_2 wt%	C_3–C_5 wt%	C_{6+} wt%	InSitu Density Sensor, g/cm^3	InSitu Viscosity Sensor, cP	Contamination, %	Fluorescence	Fluid Type
Well 1											
DFA 1	XX,240	1,423	13.17	1.91	5.21	79.7	0.692	0.60	<5	0.76	Oil
DFA 2	XX,440	1,101	10.43	1.43	5.39	82.75	0.714	0.81	<5	0.42	Oil
DFA 3	XX,675	52,029	85.54	0.1	3.1	11.25	0.288	0.20	<5	0.06	Gas
DFA 4	XX,110	612	5.54	1.59	4.93	87.94	0.779	1.30	<5	0.36	Oil
DFA 5	XX,140	536	4.8	1.49	4.62	89.08	0.78	1.30	<5	0.23	Oil
DFA 6	XX,150	na	na	na	na	na	0.979	na	<5	na	Water
Well 2											
DFA 1	XX,450	1,352	12.67	2.05	4.44	80.84	0.698	**0.60**	<5	0.75	Oil
PVT LAB	XX,450	1,160	10.86	1.13	6.06	81.95	0.684	**na**	3.8		Oil
DFA 2	XX,460	1,274	12.02	1.9	4.56	81.52	0.702	0.65	<5	0.64	Oil
DFA 3	XX,480	1,274	12.23	2.12	4.15	81.5	0.702	**0.68**	<5	0.5	Oil
PVT LAB	XX,480	1,187	10.37	1.1	6.41	82.12	0.698	**0.60**	2.5		Oil
DFA 4	XX,010	1,169	11	1.81	4.81	82.33	0.715	0.68	<5	0.47	Oil
DFA 5	XX,130	1,138	10.68	2.15	4.27	82.9	0.723	**0.78**	<5	0.54	Oil
PVT LAB	XX,130	990	8.87	1.23	5.87	82.14	0.721	**0.72**	2.4		Oil
DFA 6	XX,240	620	5.74	1.52	4.43	88.31	0.767	1.12	<5	0.22	Oil
DFA 7	XX,480	na	na	na	na	na	0.979	na	<5	na	Water
DFA 8	XX,150	na	na	na	na	na	0.985	na	<5	na	Water

na= not applicable

FIGURE 2. The table presents DFA results for all stations across both wells. Reservoir fluid samples also were collected at all stations and sent to a PVT laboratory for surface analysis. The PVT-laboratory-measured fluid properties results are available for three stations, which are noted for comparison with DFA data (bold). (Source: Schlumberger)

accurately analyze compositional gradients as well as vertical and lateral reservoir connectivity to estimate the economic value of a reservoir—a critical factor in appraisal and early field development. Accurate and timely viscosity data are important for optimizing the production phase of every well. Developed for both land and offshore applications, the viscosity sensor is particularly critical for the deepwater sector, where cost, risk and uncertainty are very high.

Murphy Oil deployed the viscosity sensor in a Gulf of Mexico (GoM) field test to perform real-time *in situ* measurements by flowing low or noncontaminated reservoir oil using a WFT sampling toolstring. The sensor, only 5 cm in diameter, is installed in the Schlumberger InSitu Fluid Analyzer (IFA) system that provides accurate measurements of bottomhole flowing pressure, temperature and fluid properties, including *in situ* density, fluid composition, GOR and now *in situ* viscosity with the new sensor.

Comprehensive analysis of IFA measurements helps the operator more fully understand the reservoir's behavior. The new sensor measures viscosity in close proximity to other *in situ* sensor measurements, providing an integrated approach to decision-making for a broad range of formation issues such as assessing well connectivity and fluid gradients at different layers and depths.

Stability with vibrating wire

The unique sensor employs a vibrating wire, a miniaturized device that provides real-time, *in situ* and high-accuracy data via specific physics of measurement created exclusively to determine fluid viscosity downhole, allowing reservoir managers to make decisions on the spot. The tool overcomes the limitations of existing technologies used to determine viscosity as secondary measurements such as the resonant rod that measures density. Under favorable conditions, it can generate an accurate viscosity output. However, the installation of both the resonant rod sensor and the viscosity sensor in the IFA offers the most reliable measurement of both density and viscosity, especially in challenging fluid conditions.

The viscosity sensor can operate in hydrocarbons ranging from 0.2 cp to 300 cp, with proven accuracy of

10% in environments up to 25,000 psi and 177 C (350 F), and provides accurate temperature measurement of flowing fluid. It delivers accurate viscosity measurements every second, enabling a real-time evaluation.

The calibration of the sensor is performed against standardized canon fluids in the engineering facility where it is built. The sensor was tested in 65 wells globally—40 drilled with oil-based mud and 25 with water-based mud, with temperatures ranging from 32 C to 144 C (89 F to 292 F) and pressures from 643 psi to 24,442 psi (Figure 1).

Sampling and DFA, including viscosity measurements, were performed in two deepwater GoM wells with the objective of properly evaluating the reservoir and establishing important fluid characterization parameters and connectivity. Understanding connectivity is especially important in the GoM, where understanding reservoir compartmentalization is a major challenge for operators.

In both wells, the WFT was set on the wellbore wall at various depths, and reservoir fluid was pumped into the IFA flowline, where the *in situ* viscosity sensor and *in situ* density sensors made their DFA measurements. The objective was to obtain a clean sample of reservoir fluid with less than 5% contamination from drilling fluid and perform *in situ* fluid typing for reservoir valuation. On each station, carbon content, fluorescence, density, viscosity, pressure and temperature were measured as well as GOR, an important indicator of whether the fluid was light or heavier oil.

In Well 1, fluid sampling and DFA were conducted at six stations, including four oil, one gas and one water station. *In situ* viscosity measurements were taken at the four oil stations. Well 2 involved a comparative study, with sampling and DFA performed at six oil stations and two water stations. Following the wireline operation, PVT lab analysis was done for three of the oil stations, with viscosity measured in two of those to compare lab data to the measurements provided by the vibrating wire sensor. The comparison showed good agreement between the two testing methods. DFA, performed with the vibrating sensor on the clean fluid in the flowline, confirmed contamination levels of less than 5% at all stations in both wells (Figure 2).

Determining reservoir connectivity

In Well 1, *in situ* viscosities in the four oil stations ranged from 0.6 cp in DFA station one at a deeper depth to 1.3 cp in stations four and five at shallower depths. In DFA station two, fluid cleanup started during the pump-out phase, and the *in situ* viscosities from both the vibrating wire and the resonant rod sensors began to stabilize after about 25 minutes of pumping. The viscosity measurement from the resonant rod later began to drift upward, a possible result of solids sticking in the sensor. Therefore, only the vibrating wire viscosity measurement (0.81 cp) was used from that station.

In Well 2, the DFA measurements across the upper reservoir indicated flowing oil from the top three oil stations and flowing water from the bottom station. Optical density, fluorescence and viscosity (0.58 cp to 0.68 cp) showed consistent compositional variance. The fluid was in equilibrium, and the tested oil zones likely were connected, a conclusion supported by other petrophysical logs and geological information.

In the lower reservoir, the DFA measurements, including pressure, mobility, downhole fluid properties and basic logs, revealed that the top two stations were oil, the next deepest station was water and the bottom zone consisted of oil. The optical density, viscosity and fluorescence measurements confirmed that the bottom sands had much higher viscosity than the upper sands. The water zone verified the presence of a barrier, most likely shale, meaning the upper and lower sands in this section were not connected. This provided the operator with valuable information to calculate accurate reserve and production estimates and determine if the well was economical. In some cases the information can help operators plan a viable completion and production strategy that will differ from that used in a connected reservoir.

By measuring *in situ* viscosity in real time, the vibrating wire viscosity sensor represents an important step-change in DFA, providing operators with a stable and precise method to better understand the reservoir's petroleum system, including connectivity and compartmentalization, and develop wells economically with reduced risk, cost and uncertainty. E&P

References

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