Quantifying Contamination Using Color of Crude and Condensate

Establishing the level of oil-base and synthetic mud-filtrate contamination in fluid samples is critical for obtaining meaningful data on fluid properties. New tools and techniques now allow real-time, quantitative measurement of contamination in gas-condensate and oil reservoirs.

In deepwater areas, an oil or gas company may spend tens of millions of dollars drilling a well to prove the presence of hydrocarbons, and then plug and abandon the well almost immediately. The operator may take years designing and building facilities before drilling another well in the field. Exploration wells provide a narrow window of opportunity for collecting hydrocarbon samples to make development decisions; therefore, obtaining high-quality samples is imperative whether the prospect is in deep water or on the continental shelf, in China, Canada, the Caspian, or elsewhere.

Testing well production is a good way to obtain fluid samples, but that is not always feasible for economic or environmental reasons. Downhole samples define fluid properties that are used throughout field development. Estimates of hydrocarbon volume, bubblepoint pressure and gas/oil ratio (GOR), simulation of reservoir flow and placement of wells all depend on formation-fluid properties. Hydrate, asphaltene and wax formation must be controlled or treated. Presence of corrosive gases affects the choice of materials for flowlines and surface facilities. These examples illustrate the wide impact that hydrocarbon composition and behavior have on planning a new field.1
Openhole-wireline or drillstring-conveyed formation testers analyze selected fluid properties downhole and acquire small volumes of reservoir fluid for later testing in a laboratory. However, mud filtrate invades the formation during drilling, so these fluid samples usually are contaminated.

During the past few years, real-time methods have been developed as part of the openhole logging suite of services to analyze sample contamination. These methods ensure that representative fluid samples are collected and minimize tool-sticking risks by introducing efficiencies in sample collection. Until recently, these sampling methods were unreliable in holes drilled with oil-base and synthetic muds or in formations with high GOR.

This article reviews the requirements and challenges in sampling reservoirs and reports on advances in evaluating sample contamination. Except where explicitly stated to be contamination from water-base mud, this article discusses oil-base or synthetic-base mud-filtrate contamination. We describe a technique for determining the time required to collect an acceptable fluid sample at a given sampling station and show how proven sample-contamination measurements can be extended to high-GOR fluids and condensates. Quantitative contamination measurement is illustrated with case histories from offshore Newfoundland, Canada, the Gulf of Mexico and the Norwegian North Sea.

**Obtaining Downhole Fluid Samples**

Formation fluid samples provide important data to optimize operator investment in both upstream and downstream facilities. Laboratory measurements establish standard fluid properties such as pressure-volume-temperature (PVT) behavior, viscosity, composition and GOR. In fields destined for subsea development, flow assurance is a major concern, so tests are performed to evaluate gas and solids content. Hydrogen sulfide \( \text{H}_2\text{S} \) and carbon dioxide \( \text{CO}_2 \) in oil require special handling and materials. Temperature and pressure changes in pipelines can lead to asphaltene and wax precipitation and deposition, and low seafloor temperatures can induce hydrate formation.

> The MDT Modular Formation Dynamics Tester tool configured for fluid-sample collection.
formation. Commingling different crude oils through satellite tiebacks can dramatically alter fluid properties [above].

The data-acquisition process must include fluid characterization to get the most out of every prospect. Taking fluid samples early in the life of a well ensures that fluid composition and properties are available for timely input to field planning decisions. If fluid properties will affect facilities or transport, accurate fluid analysis gives an operator the opportunity to mitigate or eliminate problems through changes in production design, or to manage them through ongoing treatments such as heating pipelines—a choice between upfront capital expenditures and ongoing operating expenses.

In some fields, fluid samples can be obtained during a drillstem test (DST) or, after a well is flowing, a production test. In some cases, a well must be completed before a flow test, which can cost tens of millions of dollars in deepwater Gulf of Mexico wells. In areas such as the Grand Banks, offshore Newfoundland, Canada, operators want to minimize operation times to avoid risks such as harsh seas and iceberg hazards. Environmental concerns restricting flaring and removing fluids from the rig also restrict use of DSTs and production tests. The cost and risk of DSTs lead operators to use wireline tools for fluid-sample acquisition.

A major problem in downhole fluid-sample collection is contamination from drilling-mud filtrate entering a tool with reservoir fluids. Contamination from water-base mud (WBM) can be discriminated easily from reservoir oil. In many of today's high-risk wells, oil-base muds (OBMs) and synthetic oil-base muds (SBMs) are used to ensure compatibility with shales, improve wellbore stability and increase drilling speed. OBM and SBM filtrates mix with reservoir crude, making quantification of contamination much more difficult than when using WBM. Fluid properties are often extrapolated to an uncontaminated condition by mathematically removing the contaminant from the distribution of constituents. However, extrapolation from high levels of contamination is risky—most companies avoid liquid-phase contamination greater than 10% on a volume-to-volume basis.

Several commercially available tools have fluid-sampling capabilities, including the Schlumberger MDT Modular Formation Dynamics Tester tool, the Baker Atlas RCI Reservoir Characterization Instrument tool, and the Halliburton RDT Reservoir Description Tool sondes. Most wireline formation testers press a probe against the borehole wall at a specified depth, pump down the formation and draw in fluid for evaluation, and then collect samples when desired fluid characteristics are reached.

With a probe securely pressed against the borehole wall, a short, rapid pressure drop breaks the mudcake seal. Normally, the first fluid drawn into the tool will be highly contaminated with mud filtrate (next page, top). As the tool continues to withdraw fluid from the formation, the area near the probe cleans up, and reservoir fluid becomes the dominant constituent. The time required for cleanup depends on many parameters, including formation permeability, fluid viscosity, the pressure difference between borehole and formation, and the duration of the pressure difference during and after drilling. Increasing pump rate can shorten the cleanup time, but the rate must be controlled carefully to preserve the reservoir-fluid condition. Because many factors affecting cleanup time have unknown values, determining the contamination level during a logging job is crucial to obtaining good samples.

The versatile Schlumberger MDT system performs a variety of functions, depending on which modules are joined together. The tool’s primary purposes are to obtain formation-fluid samples, to measure formation pressures at given points in the reservoir and to estimate permeability in situ. For a description of use of the tool for permeability measurement and description of other tool modules, see “Characterizing Permeability with Formation Testers,” page 2.

The OFA Optical Fluid Analyzer system in the MDT tool has provided a qualitative measure of contamination since its introduction in 1993. Schlumberger has developed the OCM Oil-Base Contamination Monitor technique to predict the time needed to achieve an acceptably low level of contamination at a given sampling station. This reliable new technique monitors sample contamination quantitatively, adding confidence to these crucial contamination measurements.
The new LFA Live Fluid Analyzer module adds a methane detector that provides a more definitive measure of gas content in the oil phase and allows calculation of GOR. This module can be used to ensure that the fluid remains in single phase during sampling; dropping pressure below the bubblepoint would make the fluid unrepresentative. The quantitative OCM contamination measurement can be used with either an LFA or OFA module (previous page, right).

Modular reservoir sample chambers (MRSCs) are available to collect large samples (below). Multiple 6-gallon [22,712-cm³] chambers can be run at the bottom of the tool string to act as dump chambers. Samples for PVT analysis are more commonly collected in smaller chambers. A multisample module (MRMS) allows collection of six easily removable sample bottles (MPSR) that are certified for transport by the US Department of Transportation (DOT) and by Transport Canada. The 450-cm³ [0.12-gal] MPSR bottle is reduced to 418 cm³ [0.11 gal] when an agitator is added to improve fluid mixing in the laboratory. The Schlumberger Oilphase single-phase multisample chamber (SPMC) can be used in the MRMS when keeping a reservoir fluid sample in.


<table>
<thead>
<tr>
<th>MRSC</th>
<th>Non-H₂S</th>
<th>MRMS</th>
<th>MPSR</th>
<th>SPMC</th>
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<td>14 kpsi</td>
<td>10 kpsi</td>
<td>20 kpsi</td>
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<td>Downhole temperature</td>
<td>204°C [400°F]</td>
<td>204°C</td>
<td>204°C</td>
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<tr>
<td>Surface heating allowed</td>
<td>77°C [170°F]</td>
<td>54°C [130°F]</td>
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<td>104°C [212°F]</td>
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<td>Volume</td>
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<td>1- and 2.75-gal options</td>
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<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Pressure compensated</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
</tbody>
</table>

The 25-kpsi limit is for special high-pressure modules, and the sampling must be done in low-shock mode—the bottle is compensated to hydrostatic pressure behind the piston. Only Schlumberger Oilphase is allowed to heat chambers above 54°C [130°F]. Six-gallon bottles must be run on the bottom of the string. Several bottles can be combined in one string. Addition of an agitator reduces this volume to 418 cm³ [0.11 gal]. Transportable indicates US Department of Transportation Exemption and Transport Canada Permit for Equivalent Safety. Compressed nitrogen is used to compensate the sample pressure so it does not decrease as much upon cooling when brought to surface.

^ Sample bottles available for the MDT tool.
single phase from the downhole collection point to the PVT laboratory is necessary. After the MDT pumpout module fills a SPMC chamber at formation pressure, a preset nitrogen charge is released. Acting through a piston floating on a synthetic oil buffer, the nitrogen adds sufficient overpressure to keep the fluid in single phase during retrieval to surface.

**Black Oil Isn’t Always Black**

Oils have color—black, brown, red, tan and even green crude oils have been seen. The hue and intensity of light transmitted or reflected from crude oil or gas condensate depend on the light’s interaction with molecules and molecular bonds in the fluid. Measurements of this interaction can be used to distinguish oils of different compositions.

The unit of light absorption or optical density (OD) is the logarithm of the ratio of incident-light to transmitted-light intensity. Therefore, darker fluids have higher OD, and a one-unit increase in OD represents a factor of ten decrease in transmittance. An OD of zero indicates all light is transmitted, while an OD of two represents 1% transmission. A fluid’s OD varies with the wavelength of incident light.

Reduction of transmitted-light intensity can be caused by one of two physical processes. Some light is scattered by particles in the fluid; scattering outside the optical path to the detector decreases intensity. Light also can be absorbed by molecules in the fluid. The MDT optics relies on differences in absorption in visible and near-infrared portions of the electromagnetic spectrum to discriminate fluids in the flowline.

Pure, light hydrocarbons such as pentane are essentially colorless; they do not absorb light in the visible spectrum. Condensates may be clear or lightly shaded reddish-yellow to tan, because they absorb more from the blue end of the spectrum than from the red end. Heavier crude oils, which contain more complex molecules, absorb light strongly throughout the visible region, making them dark brown or black.

Light with a wavelength in the visible or near-infrared spectra, referred to as the color region, interacts with a molecule’s electronic energy bands. Compared to less complex molecules, larger and more complex aromatic hydrocarbon molecules, such as asphaltenes and resins, absorb light having longer wavelengths.

Because heavier oils contain more aromatic compounds, they tend to have darker coloring than less dense oils and condensates. Waxes are colorless, but if the molecules are long enough, they will scatter light and appear white.

Despite the differences in optical absorption of various reservoir oils caused by composition, there is a common behavior. Electronic absorption generally decreases as wavelength increases. The OD decay in the visible and near-infrared region can be characterized by a single parameter, which can be thought of as the color of the oil.

To understand how OD measurements can be used to quantify contamination, it is important to distinguish between absorption in the color region by two kinds of hydrocarbons: complex aromatics and saturated aliphatics. Complex aromatics contain carbon rings with both single and double carbon-carbon bonds, which are excited by visible and near-infrared light. Aliphatic compounds are open chains of carbon atoms. If all the carbon-carbon connections are single bonds and other bonds are with hydrogen, the aliphatic molecule is termed saturated. Only high-energy ultraviolet light can excite saturated aliphatic molecules, so they have a low OD in the color region of the spectrum.

Black oils contain many complex aromatic compounds, whereas natural OBMs comprise mostly saturated compounds; SBMs are made only from saturated aliphatics. The difference in chemical composition between reservoir-crude oil and drilling-mud filtrate makes OD a good measure of filtrate contamination in crude oil.

### Optical density of various oils

<table>
<thead>
<tr>
<th>Wavelength, nm</th>
<th>Optical density</th>
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</thead>
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<td>500</td>
<td>0</td>
</tr>
<tr>
<td>1000</td>
<td>0.5</td>
</tr>
<tr>
<td>1500</td>
<td>1.0</td>
</tr>
<tr>
<td>2000</td>
<td>1.5</td>
</tr>
<tr>
<td>2500</td>
<td>2.0</td>
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</tbody>
</table>

**Exciting Molecules**

Water can be distinguished from oil easily, because it is highly absorbing at near-infrared wavelengths around 1445 and 1930 nanometers (nm), where oil is relatively transparent (next page, top). Oil has a strong absorption peak around 1725 nm, where water does not. These peaks come from the interaction of light with vibrational energy bands in carbon-hydrogen bonds for oil and oxygen-hydrogen bonds for water. Molecules containing such a bond absorb photons of the proper wavelength, and the photon energy is converted into molecular vibration. Monitoring absorption at these three wavelengths differentiates between water and oil.

Hydrocarbon compounds comprise linked chains, branches or rings of carbon atoms, each having hydrogen atoms attached. Typically, a carbon atom will bond with two other carbon atoms and two hydrogen atoms. Carbon atoms at the end of a molecule will have three hydrogen atoms attached, while those at a branch, connecting with three other carbon molecules, will have only one hydrogen bond. Methane is a single carbon molecule with four hydrogen atoms attached.

The oil peak in Channel 8 of the OFA module measures molecular absorption of light by carbon atoms having two hydrogen atoms attached, which are the primary constituents of reservoir fluids.
oils. A high-resolution optical spectrometer reveals this oil peak in much greater detail, showing several absorption peaks in hydrocarbon fluids (right). Although methane has some absorption at the oil peak, there is no absorption by hydrocarbons with more than one carbon atom at the methane peak. This provides an ideal discriminator for methane content in live crude oils—utilized by a new MDT tool, the LFA Live Fluid Analyzer module. The detection channel tuned to that wavelength replaces the OFA module’s shortest wavelength color band in Channel 0.

Absorption spectrum. The MDT tool monitors light absorption starting in visible wavelengths and extending into the near-infrared. The ten channels of the OFA module, numbered 0 through 9, are shown. In the color region on the left, crude oils have a rapidly decaying absorption, caused by interaction of light with electrons in the molecules. More complex aromatic molecules (green shapes) absorb at longer wavelengths. Channels 6 and 9 are tuned in the middle of molecular vibrational peaks for water; Channel 8 is in the molecular vibration peak for the CH2 bond in hydrocarbons. Channel 0’, which replaces Channel 0 in the LFA module, is tuned to the methane peak.


4. A live crude oil evolves significant quantities of gas when its pressure and temperature are lowered. A dead oil does not evolve gas at atmospheric pressure and room temperature. Stock-tank oil, the liquid emerging from the final surface separator, contains little gas.

High-resolution vibrational absorption spectrum of heptane, methane and a mix of the two. Heptane (green) does not absorb light at the CH4 methane peak. Methane absorption (red) at the CH2 oil peak is low. Absorption of a mixture of the two (black) is the sum of the individual absorptions, according to the Beer-Lambert law. The LFA module has a channel set at the methane peak.
The Key to Quantifying Contamination

The MDT tool includes an optical module with two devices designed to monitor contamination in OBM systems. A gas refractometer uses light from a diode reflected off a sapphire window to qualitatively identify the fluid phase in a flowline (left). At the selected angle of incidence, the reflection coefficient is much larger when gas is in contact with the window than when oil or water contacts it.5

The second detector in the OFA module uses transmitted light to evaluate absorption characteristics of a fluid. A high-temperature tungsten halogen lamp provides a broadband source of light that passes along optical guides and through a 2-mm thick optical chamber in the flowline. The distribution of transmitted light is recorded at 10 wavelengths in the visible and near-infrared spectra. Two of these channels detect the strong water-absorption peaks, indicating water content in the fluid when compared with the strong hydrocarbon-absorption peak.

Discriminating gas and water from oil is simpler than distinguishing between crude oil and OBM or SBM filtrate, because crude, OBM and SBM all absorb strongly at the oil peak near 1725 nm. Fortunately, oils have different color according to the quantity of large, complex aromatic compounds they contain. This affects absorption in the MDT spectrometer in the shorter wavelength channels constituting the color region. Since SBM and OBM contain simple aliphatic compounds, their absorption in these channels is small.

In most cases, when the MDT tool first begins drawing fluid from a formation, the OD is high due to light scattering off mudcake solids in the fluid. After a few seconds, the OD falls to a low value, and then increases slowly as the mud filtrate drains from the formation near the probe and is replaced by darker crude oil.

Particles of mudcake or other solid material generate noise in the absorption channels. Scattering caused by these particles is wavelength-independent, so the effect can be removed by subtracting a nearby channel. In the color region, absorption decreases quickly enough that skipping a channel and subtracting from the next one down removes noise due to scattering without significantly affecting the signal (left). The result is a smoothly varying contamination curve.6

The change in OD as reservoir crude replaces mud filtrate in the flowline follows the Beer-Lambert law, which states that a mixture of two
oils has an OD that is a linear, volumetrically weighted combination of the two individual ODs, evaluated at each wavelength. A change in OD is directly related to a change in composition (right).

Because most OBM s and SBMs mainly contain simple aliphatic compounds, their OD is effectively zero except in the lowest MDT channels. With one endpoint determined, quantitative evaluation of contamination through OD requires a method for finding the other endpoint—the OD of uncontaminated crude. This comes from understanding the way fluids move during cleanup. Fluid withdrawal through the probe creates an expanding pressure sink around the wellbore. The OCM analysis fits the cleanup data with a curve—having a specific shape based on the physics of the tool and wellbore—to determine the remaining amount of filtrate contamination. In one well, five samples were captured in the MDT tool at different times during cleanup. The laboratory results show contamination results consistent with the OCM model (above).

Quantitative prediction of contamination. Fluid samples were taken at five times during cleanup. Color channel data from the OFA module are fit using the OCM model (left) to determine contamination cleanup (right). The OCM prediction of contamination levels agrees well with laboratory contamination measurement (table).

### Table: Sample Results

<table>
<thead>
<tr>
<th>Sample</th>
<th>Pumping time</th>
<th>OCM contamination</th>
<th>Laboratory contamination</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>695 sec (12 min)</td>
<td>17%</td>
<td>22%</td>
</tr>
<tr>
<td>2</td>
<td>940 sec (16 min)</td>
<td>13%</td>
<td>17%</td>
</tr>
<tr>
<td>3</td>
<td>1264 sec (21 min)</td>
<td>12%</td>
<td>13%</td>
</tr>
<tr>
<td>4</td>
<td>1681 sec (28 min)</td>
<td>9%</td>
<td>11%</td>
</tr>
<tr>
<td>5</td>
<td>2250 sec (37 min)</td>
<td>5%</td>
<td>10%</td>
</tr>
</tbody>
</table>

### Figure: Beer-Lambert Mixing

Light absorption for crude oil (brown) is greater than for OBM filtrate (yellow) (left). The Beer-Lambert law says that the optical density (OD) of mixtures of the two (shades from yellow to brown) is related to the relative proportion of the two fluids. As the fluid cleans up, the OD increases from the OBM value OD₁ asymptotically to the crude-oil value OD₅ (right).

### References

6. Mullins OC, Schroer J and Beck GF: “Real-time Quantification of OBM Filtrate Contamination During Openhole Wireline Sampling by Optical Spectroscopy,” Transactions of the SPWLA 41st Annual Logging Symposium, Dallas, Texas, USA, June 4-7, 2000, paper SS.

Like the other optical-detection bands, the methane channel of the LFA module displays a high OD as mud solids pass through a tool’s flow-line after pumping begins. Since drilling muds do not contain methane naturally, the initial high concentration of filtrate drawn into the MDT tool during cleanup results in a substantial drop in the OD recorded in the methane channel. As reservoir fluid replaces filtrate in the line, the signal OD increases in proportion to the oil’s methane content, generating the same curve shape as cleanup with the OFA tool (left).

Time for complete cleanup cannot be predicted before the logging run, because there are too many unknown reservoir variables. For example, there is not a direct relationship between formation permeability and cleanup time. Although fluid can be pumped quickly from a high-permeability formation, which would imply a short cleanup time, that high permeability may have allowed mud filtrate to penetrate deeply into the formation before the wireline run. In that case, cleanup time could be long. Collecting fluids close to a shale stringer can shorten cleanup time, since the shale provides a flow barrier, allowing collection of less contaminated reservoir fluid farther away from the wellbore.

The ability of the OFA and LFA modules to quantify contamination levels while pumping allows sampling decisions to be made in real time. The OD for all channels is transmitted to surface at high rate, and the OCM software updates its analysis every 20 seconds. Once sufficient data have been acquired, the software selects the color channel that will provide the best fit to the expected trend and shows the degree of contamination and the time required to achieve an acceptably low level of contamination.

In a Gulf of Mexico well, the MDT probe was set within a massive sand, and the tool measured a mobility of 87 millidarcies per centipoise (mD/cp). After pumping for 71 minutes, the OCM software predicted an additional 4 1/2 hours pumping time to achieve an acceptable level of 10% contamination (left). Rather than wait or waste a sample bottle on highly contaminated fluid, the operator chose to move to another level within the same formation.

The tool was moved 44 ft [13 m] lower in the formation. The mobility was higher, 256 mD/cp. Contamination dropped to 9% within 132 minutes, and samples taken at this location were acceptable for PVT analysis (next page, bottom).
Scattering Light
Scattering from particles smaller than the incident-light wavelength—several hundred nanometers diameter—depends on the wavelength of incident light. The intensity of this scattering increases with decreasing wavelength. This effect, called Rayleigh scattering, gives the sky its blue color.

Wavelength-independent scattering is removed by channel subtraction, but this leaves some wavelength-dependent Rayleigh scattering. For the OCM-color procedure, a longer-wavelength channel is subtracted, but for the OCM-methane procedure, the subtracted channel is at a shorter wavelength. Since one procedure slightly overcorrects for wavelength-dependent scattering and the other slightly undercorrects, averaging OCM-color and OCM-methane contamination values from the LFA tool tends to remove some of that scattering effect (right).

Discrepancies between the contamination determinations indicate the need to look more closely at other channels to identify the cause before collecting a fluid sample. Methane detection has been shown to be valid for fluids with GOR as low as 700 scf/bbl [126 m³/m³]. However, in reservoirs containing oil with low methane content, color channels may provide better information on contamination than the methane channel does. For gas-condensate fluids, methane detection using the LFA module is essential, because even in the shortest wavelength color channels, OD remains low and the progression of cleanup using the OCM-color procedure is difficult to assess. In some cases, a drilling-mud filtrate may be darker than the condensate, and the OCM-color procedure may not be able to discriminate contamination from reservoir fluid. The OCM-methane detection in the new LFA module works well in such cases.

Comparing Contamination at Surface
Samples are collected to determine properties of reservoir fluids such as PVT behavior. Mud filtrate mixed in the sample must be accounted for to arrive at reasonable estimates of reservoir-fluid properties. The DFA and LFA modules measure...

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Wavelength-dependent scattering. The optical absorption response in the pumping period between 1000 and 1500 seconds indicates some scattering remains even after subtracting a baseline channel. This wavelength-dependent response is stronger in the color channel (purple) than in the methane channel (blue). The noise in the data after 2500 seconds occurred during sample collection. The OCM method was still able to fit the data, predicting 7% contamination based on the average of color and methane data of 7.9% and 6.0%, respectively.

Obtaining acceptable samples. After about two hours of pumping, contamination had dropped to about 9% (blue curve). OD for all channels is shown in the inset (shaded green). The OCM model was fit to data of Channel 4 minus Channel 6 (red curve) between the start- and end-fit lines (green dashed lines). The increases in OD past the end-fit line occurred during sample collection.
contamination in real time before collecting samples. At the rig floor or in a laboratory, sample contamination can be analyzed further using a gas chromatograph (GC), a gel-permeation chromatograph (GPC), tracer analysis or, less commonly and not discussed here, a nuclear magnetic resonance (NMR) spectrometer.

In a GC, a small quantity of sample fluid is injected into a carrier gas such as high-purity helium. Light gaseous components are separated using a molecular sieve and heavier components are separated using a packed chromatographic column. A molecular sieve relies on particle size for separation, with smaller molecules staying in the sieve longer. In a packed column, the gas flows past particles coated with a fluid, termed the stationary layer in a GC because the gas does not mobilize it. The relative solubility of components in the stationary layer separates them as the carrier gas moves a sample through the column. Chromatographs are calibrated for sample components.

The process is similar for a GPC except the inert carrier is a liquid, and constituents do not separate as well at the detector. Component peaks from a GC are typically distinct, but those from a GPC can be smeared together. The Oilphase FFA Field Fingerprint Analyser rigsite incorporates a GPC.

At the end of the column, the carrier gas or liquid containing the sample enters a detector. For hydrocarbons, this is usually a thermal-conductivity detector or a flame-ionization detector. Some detection methods respond to mass and others to the number of carbon atoms in the molecule.

The distribution of crude-oil constituents normally declines smoothly with increasing carbon number beyond eight. OBM and SBM filtrate contamination causes this distribution to deviate from the expected shape. SBMs use a narrow range of molecular weights, so contamination can be discerned with both a GC and a GPC as a sharp increase in the frequency of molecules between carbon numbers of C_{16} and C_{18} (above). OBMs with a mineral-oil base include a broader range of compounds, perhaps ranging from C_{6} to C_{20}, and are difficult to distinguish using a GPC. Often, these muds can be separated from the crude-oil signature when using a GC. Drilling muds that include produced reservoir oil cannot be distinguished from formation oil using either form of chromatography, unless a tracer is added to the mud.

An OBM or SBM filtrate response also can be removed from the GC result by separately measuring the response of the filtrate, normalizing the two signals and subtracting. Drilling-mud composition must be maintained while drilling an open-hole section before sampling because variations in mud composition add error to the analysis.

Some discrepancy between methods is expected, as all methods have potential errors. The FFA device can overestimate contamination if the mud is not synthetic; even with SBM, both the FFA results and GC methods assume a distribution of hydrocarbon constituents to determine contamination. Tagging is expensive and in principle can be accurate, but in practice, it may not obtain reliable results. It is difficult to ensure that all the drilling mud has a uniform concentration of the chemical or isotopic tag and that the tagged molecules have the same physical and transport properties as the rest of the filtrate. The OCM-color method has problems when the mud filtrate has significant color or the reservoir oil is colorless, because the method requires a contrast between the two. However, the LFA-OCMmethane method provides a solution for such cases, since it is based on methane concentration.

Even if contamination-detection methods always were correct, many errors can occur in collecting samples. The fluid can go through a phase transition as it is drawn into the tool, leaving components behind in the formation, or phases can separate in the tool. Valves can fail, either not opening properly downhole and capturing insufficient fluid or not closing completely and losing pressure and fluid after sample collection. At surface, every time the fluid is transferred...
or a sample bottle is handled, there is potential for damaging the sample. Bottles should be heated and agitated for about five days before performing laboratory analyses, but not all laboratories follow this recommended procedure. Collecting the right base oil of the drilling mud—used to compare with spectra of contaminated reservoir oil—is difficult because mud composition often changes during a job as components are added to control various drilling problems.

Collection and analysis of fluid samples are important; operators must control sources of error to obtain the best possible data. The OFA and LFA procedures measure properties downhole in real time before sample collection, a distinct advantage. The few sample bottles available on the tool are not wasted storing bad samples. Since OCM measurements are made before any possible transport and handling problems, they provide a check for the quality of later measurements.

When sufficient information is available from the reservoir, measured values of fluid properties can be used as an additional check on sample quality. Norsk Hydro conducted a detailed study of oil samples taken from several North Sea fields. In a reservoir with a gas cap, both chemical tags and the FFA device indicated a high level of sample contamination, ranging from 8.9% to 25.8%. The OFA-OCM method and GC analysis indicated lower contamination levels of 2.6% to 6.8%. The difference in these two ranges of contamination measurement led Norsk Hydro to investigate further.

Reservoir saturation pressure, $P_{sat}$, at the sampling depth was estimated from reservoir pressure and density gradients starting at the gas-oil contact (right). The reservoir saturation pressure of the sample, based on PVT


properties determined with contaminants in the fluid, was about 20 bar [2 MPa or 290 psi] below the saturation-pressure gradient at the sampling depth. These PVT properties can be mathematically corrected to remove the effect of contaminants and then compared with the reservoir-gradient calculation.

When using the FFA contamination value of 9%, the resulting calculated $P_{sat}$ was greater than the reservoir pressure, which is an unphysical result. When using the OFA-OCM value of contamination, $P_{sat}$ was about 10 bar [1 MPa or 145 psi] below the expected value. This indicates the sample may have lost gas before PVT properties were evaluated. Gas could separate from liquid in the formation due to near-well pressure drawdown, but the downhole conditions were not known well enough to evaluate this effect. The investigation focused on what happened to the sample coming out of the hole.

The sample bottle did not allow for downhole pressure compensation. The fluid could enter the two-phase region due to cooling from the reservoir temperature of 107ºC [225ºF] during transport to surface. The sample had probably cooled below 102ºC [217ºF]—the temperature at which pressure in the enclosed chamber decreased below the bubblepoint—and was in two phases by the time it reached the surface. The 450-cm³ bottle has a dead volume of 2.5% between the isolating valve on the bottle and the valve on the downhole flowline, which could have been filled with gas that was lost when the valves were opened at the surface. The PVT properties of the contaminated samples can be corrected for this gas loss, increasing the contaminated-sample bubblepoint pressure by 10 bar. When the gas-loss correction is combined with removal of the contamination, as measured by the OCM-color method, $P_{sat}$ increased to within 4 bar [0.4 MPa or 58 psi] of the expected reservoir value, which is reasonable agreement. This analysis could not have been performed without the downhole OCM-contamination measurement.

**Monitoring Gas Directly**

Gas-condensate fields engender additional difficulties for fluid sampling when OBM and SBM are used. Although they contain single-phase fluids in the reservoir, gas condensates separate into a gas phase and a liquid phase when conditions drop below the dewpoint. The liquid derived from gas condensates is a more valuable commodity than the gas. Surface-separator conditions are tuned to optimize the volume and value of liquid obtained from condensates. The separator designs often are based on fluid properties from wireline samples, so determining the level of contamination and correcting the PVT properties are essential.

OBM and SBM filtrate may mix only partially with condensate in a reservoir, leaving mud filtrate in a liquid-hydrocarbon phase and a gas phase with some of the more volatile components of the filtrate. A wireline sampling probe draws both hydrocarbon phases into the device, and samples collected contain both reservoir fluid and filtrate contamination. When the fluid pressure is lowered during laboratory testing, the phases separate. All mud filtrate is concentrated in the liquid phase; presence of contamination strongly affects a sample’s dewpoint pressure.

To calculate a correct GOR and other reservoir-fluid properties, the volume of the oil phase must be adjusted to remove contamination. That liquid-phase contamination must be kept low to avoid excessive correction factors, just as with a black oil. However, to compensate for the concentration of SBM and OBM contaminants in the liquid phase, many companies set the acceptable level of contamination in a gas condensate below that for a black oil. The LFA tool provides significant new information for gas-condensate reservoirs, improving data quality used for designing production facilities.15

A gas-condensate prospect in the Norwegian North Sea offered one of the first tests for the LFA tool, used in this case without the OCM module.16 A mobile C₃₆+ GC, capable of measuring individual constituents up to C₂₀ at the rigsite, indicated contamination of 32% to 60% in the low-pressure liquid phase. This was comparable to results from subsequent FFA analysis onshore. The LFA time-sequence data were later analyzed using the
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OCM method. Mud filtrate and the reservoir fluid were indistinguishable in the color channels. The OCM-methane analysis provided a quantitative contamination measurement, about 8% of the live oil (previous page). The operator had little experience with the new tool and sought to understand the difference.

A subsequent well test proved a gas-condensate find. Surface-separator samples collected during the flowing well test and analyzed using a C36+ GC indicated stock-tank oil contamination of 23%. A full PVT analysis provided the GOR, allowing correction of contamination to single-phase, downhole conditions. The result indicated 6 to 7% contamination, which agreed well with the OCM-methane measurement on the live fluid.

During determination of fluid properties for a gas-condensate reservoir drilled with OBM, the buildup of methane measured with the LFA module is essential to obtain accurate, real-time condensate-contamination measurement. The alternatives are to conduct a DST or complete a well with water-base mud to avoid oil contamination altogether. Moreover, using the LFA device also provides a simultaneous measurement of GOR.

The gas refractometer on both the OFA and LFA tools indicates gas only when it is in contact with the detector window. Gas bubbles may not be detected if they are in the center of the flowstream, or on the opposite side. The refractometer detects all gases, regardless of composition, so CO2 and H2S are flagged.

The LFA module also provides a complementary gas-detection system using measurement of OD in the methane channel. Although insensitive to other gases, this detector monitors all methane passing through the flowline. If live oil is flowing, the volume percentage of methane will be low. However, if the pressure drops below the bubblepoint, gas evolves and methane absorption will be high when a bubble passes the light beam anywhere within the flowline. The combination of the gas refractometer and methane detector makes a robust LFA gas-detection method (right).

The ratio of the methane peak to the oil peak in the LFA module correlates with GOR both for mixtures of pure components and for live crude oils (above). A multiplying factor applied to the methane-heptane mixtures accounts for the absence of other gases normally present in live oils. The dead crude oil (orange triangle) was evaluated after gas was removed in the laboratory.

Real-Time Fluid Typing

The combination of the MDT system and the CMR Combinable Magnetic Resonance tool revealed new insights about a reservoir operated by Shell in the Gulf of Mexico. The Yellow sand unit had been depleted for two years. The new drilling target was an underlying sandstone formation, called the Blue sand, separated from the overlying reservoir by a thick shale.

A logging-while-drilling (LWD) resistivity log revealed a 10-ft [3-m] water layer on top of the Blue sand oil, which is not a gravitationally stable situation. A thin hydrocarbon layer sat atop the water, just below the thick shale (below). The operator wanted to know whether water from above had broken through. The LWD gamma ray log and standard CMR processing did not explain how this water could be above the oil (right). Pressures collected with an MDT tool indicated that the water zone was not in pressure communication with either the Yellow sand above or the Blue sand below. Reservoir pressure in the water zone was about 800 psi [5.5 MPa] higher than the Blue sand, and was slightly less than original reservoir pressure for the Yellow sand.

The depleted Yellow sand placed a limit on the mud weight that could be used in the borehole. This created concerns about the wellbore; the well was not stable enough to leave the MDT tool in place long enough for formation fluid to clean up. The MDT tool was used instead for fluid typing with the gargling technique developed by Shell Deepwater Services. In this technique, reservoir fluids from the formation were pumped for a short period of time through the OFA module and out to the wellbore, without collecting samples in bottles. An OD spectrum from the OFA module allowed analysis of these small quantities of reservoir oil. Since oil color relates to API gravity and GOR, the color pattern from the 10 OFA channels enabled discrimination between the oils. In this case, the Yellow sand was a gas condensate with an API gravity of about 40º and a GOR of 6000 scf/bbl [1080 m³/m³], while the Blue sand held a 35º API gravity oil with a GOR of 2000 scf/bbl [360 m³/m³]. Surprisingly, the color spectrum of the hydrocarbon sitting on top of the water had the same signature as the Yellow sand above the thick shale.

The CMR log data were reprocessed to improve resolution from 18 in. [46 cm] to about 8 in. [20 cm], revealing a thin permeability barrier at the base of the water, thought to be about 6-in. [15-cm] thick. This led to a rethinking of the distinction between the top and bottom units. In other wells, the Yellow sand remained above the large shale, but in this well, a splinter member of the Yellow sand cut below the shale. The true boundary between the zones was the thin barrier, which appeared to be sand on sand, undifferentiated on conventional logs.
Had this been an exploration well, facilities planning would have relied on results from fluid sampling. Depending on where the samples were collected, the GOR could have been too high or too low, leading to an inefficient design. If the sample GOR measured were lower than the actual production, the facilities would have an undercapacity for gas production, and insufficient compression and transmission capabilities, resulting in lost or delayed revenues. Significant error in GOR in the opposite direction could have the opposite problem—an expensive overdesign with too much capacity. MDT fluid typing is a valuable means for detecting such situations.

In a well in the North Sea, Norsk Hydro drilled a pilot hole through three horizons prior to drilling a horizontal section. The typical log response in this field made distinguishing the fluid type in each formation difficult. Precise definition of fluid compositions was not required, but rapid differentiation of gas, oil and water was imperative because the rig was idle while the operator awaited this fluid identification. The operator wanted to drill a horizontal wellbore into the deepest oil-bearing zone. The MDT sonde was chosen to identify the fluids in real time.

Pumping fluid into the tool progressed until the OFA-OCM method indicated contamination had dropped below 8% in the middle zone and to 1% in the upper zone. The MDT tool indicated that the lower zone was water-filled. The low contamination values in the other zones gave the operator confidence in the tool response, which showed that the reservoir fluid was oil. A 3%-olefin tracer placed in the OBM mud before drilling the section allowed rapid confirmation of these contamination values using a GC at the rig. The surface contamination measurements—5% in the middle zone and 4% in the upper—provided reasonable agreement with the OFA-OCM measurement.

Although additional fluid samples had been collected for testing onshore, the real-time results using the OFA-OCM analysis coupled with a rigsite GC confirmation provided answers that were conclusive enough to cancel the onshore testing program. The horizontal section was drilled into the middle horizon immediately after completing the MDT run, resulting in a successful well.

Norsk Hydro no longer uses olefin tracers to tag drilling mud. Recent wells have relied successfully on the combination of the OCM method and a C36+ GC.

Fluid Compartments in Hibernia Field

The Hibernia field, discovered in 1979 and operated by Hibernia Management and Development Company, Ltd. (HMDC), was the first significant oil discovery in the Jeanne d’Arc basin on the Grand Banks of Newfoundland, Canada. Oil production commenced on November 17, 1997, from an ice-resistant, gravity-based platform in 80 m [262 ft] of water, 315 km [196 miles] east-southeast of St. John’s, Newfoundland (above).

The structure is a highly faulted, south-plunging anticline containing approximately 3 billion barrels [475 million m³] of oil-in-place, with an estimated 750 million recoverable barrels [120 million m³]. Most of these resources are in two Lower Cretaceous reservoirs, the Hibernia, and the combined Ben Nevis and Avalon sandstones. The Hibernia reservoir will be depleted

using both waterflood and gasflood processes (above). Delineation drilling of the Ben Nevis and Avalon formations continues; these reservoirs will be produced under waterflood.

HMDC encountered operational problems while drilling the first four wells using WBM. Shifting to OBM resulted in improved borehole conditions, few seal losses while running the logs and decreased logging-acquisition time.

Extensive faulting makes reservoir continuity uncertain. Early in field development, HMDC initiated a comprehensive data-acquisition plan to determine fluid compositional variation between fault blocks and within the vertically extensive fluid column. Obtaining high-quality samples with the MDT tool is an integral part of the program for determining reservoir-fluid properties. MDT pressure measurements establish pressure gradients and locate gas-oil and water-oil contacts.

Fluid samples were collected in three ways—MDT samples, bottomhole samples and separator samples. The MDT string typically was configured to obtain approximately 30 pressure points across selected reservoir intervals and included six MPSR sample bottles. Several wells were sampled using 12 sample cylinders: six

![Hibernia water- and gasfloods. The 3D image indicates some of the oil-production (green), water-injection (blue) and gas-injection (red) wells in the highly faulted reservoir (left). The structure map shows distinct fault blocks in the Hibernia formation (right). Part of the field is under waterflood (blue) and part under gasflood (red). The section line (black) indicates the location of the cross section shown on page 42.](image)

![Hibernia GOR. Fluid samples from the MDT tool and from bottomhole samples (BHS) from DSTs indicate the trend of GOR with depth. Separator samples from Hibernia are not associated with a specific depth and are not shown here. (225 m³/m³ = 1249 scf/bbl.)](image)
MPSR cylinders and six pressure-compensated SPMC cylinders. The variation of PVT properties in the MDT samples helped define depth and areal trends, which were further refined by geochemical fingerprinting of the samples. MDT detection of OBM contamination was important for the program. Use of OCM real-time monitoring allowed collection of high-quality gas-condensate samples.

Initially, bottomhole samples from the entire perforated interval were collected during production testing to obtain representative PVT properties. Single-phase flow conditions were maintained downhole during sampling. Fluid samples collected from test separators were less expensive, allowing continued monthly sampling to monitor compositional changes. Samples from the three sources have shown excellent agreement in PVT studies and determination of OBM-contamination levels (previous page, bottom).

The operator uses PVT data from these sources for well-test analysis, reserves determination, material balances, reservoir simulation, production allocation, production monitoring and fluid-metering factors, process simulation and regulatory reporting.

The initial pressure in the Hibernia reservoir was approximately 40 MPa [5800 psi]. Because the bubblepoint varies across the field, the company avoided sampling below bubblepoint pressure. The MDT tool monitored pressure during sampling, allowing minimal drawdown and accurate bubblepoint determination from recovered samples.

The OFA module detected sample contamination levels to estimate pumping time to achieve cleanup. About halfway through the sample-collection program, the OCM option became available, providing a quantitative measure of contamination in real time. The OFA results from the previous logging runs were analyzed later using the OCM-color methodology to determine contamination levels (above).

The MDT sampling tool is an effective means of collecting representative fluid samples to evaluate variations through long fluid columns. The Hibernia group has successfully run the tool on wireline, but because of wellbore deviations up to 80°, the tool typically was run as part of a TLC Tough Logging Conditions superstring. The TLC tool usually includes the Platform Express integrated tool, including the AIT Array Induction Imager Tool sonde, a caliper and gamma ray tool, and the MDT modules. Logs collected on a first pass were transmitted in real time to the company office in St. John’s where engineers picked points for MDT pressure determination and a sample-collection pass. With fluid columns in excess of 400 m [1300 ft] thick in areas of the

Comparison of contamination measurements. The OFA-OCM measurement at the wellsite agrees well with laboratory GC measurements for the gasflood (left) and waterflood (middle) zones of the Hibernia formation and Ben Nevis and Avalon formations (right).
Cross section spanning Blocks B and C in the Hibernia field gas flood area. The Hibernia formation dips steeply, plunging into the Murre fault in the northwest. The gas-oil contact (GOC) is shown at the crest. The water-oil contact (WOC) is unknown in the southeast; in the northwest it lies between the two marked depths. This section line is indicated on the map on page 40.

Gas chromatograms of reservoir and drilling-mud base oils. The sharp peaks on the curves are specific carbon compounds, such as normal-alkane \( C_{20} \) \( [n-C_{20}] \). Pristane (Pr) and phytane (Ph) are geo-markers found in reservoir fluids. A scaling factor is applied to the base-oil spectrum before subtracting it from the reservoir-oil spectrum. The scaling factor is related to the degree of contamination.
field, using MDT pressures and fluid-type determination to establish gas-oil and water-oil contacts was important (previous page, top). A significant benefit of the MDT logging program is real-time decision-making on sample collection points.

MDT fluid-sample composition was determined in a PVT laboratory by the GC method. The chromatogram of the base oil of the mud was subtracted from the sample GC spectrum (previous page, bottom). The resulting peak-height spectra from different blocks, coupled with other PVT data such as the bubblepoint pressure, GOR and formation volume factor, provided evidence to correlate oil from different fault blocks, indicating seven distinct fluid regions across the field (above). With this information, gasflooding and waterflooding can be implemented more efficiently. Formation pressures from openhole MDT runs also indicated whether offset production had drawn down formation pressure in the new locations. Other measurements made on the reservoir fluids, including wax content, sulfur content, acid number, pour point, cloud point and saturates-aromatics-resins-asphaltenes content, also indicated variations by fault block, impacting the production and completion strategies.  

**A Downhole Chemistry Laboratory**

Distinguishing fluid phases may seem like some of the simplest chemistry that can be performed. Doing it from miles away, in a harsh environment, is the significant new accomplishment of the MDT tool. The channels of absorption information in the OFA tool have allowed correlation with many more attributes of the fluid: oil-shrinkage factor, bubblepoint pressure, oil compressibility, oil density and average molecular weight. Minimizing contamination in collected samples and controlling phase separation during collection to enhance the value of in-situ fluid properties measurements is an ongoing challenge. The additional capabilities in the new LFA module provide direct measurement of methane content, allowing estimation of GOR and a more robust gas flag to avoid taking the fluid into the two-phase region. In addition, obtaining fluid samples from behind casing is significantly easier now. The CHDT Cased Hole Dynamics Tester tool can drill up to six holes through casing in one trip and, in combination with other MDT modules, obtain samples and monitor contamination in real time. It then seals the hole through the casing with a corrosion-resistant plug rated to 10,000-psi (69-MPa) differential pressure.

Already, significant decisions are made based on real-time downhole fluid measurements. Continuing development will improve the range and reliability of these measurements. —MAA  

19. The pour point is the lowest temperature at which an oil will begin to flow under standard test conditions. The cloud point is the temperature at which paraffin molecules first start to crystallize from oil, as observed visually.  