Reservoir-fluid properties play a key role in designing and optimizing well completions and surface production facilities to manage reservoirs efficiently. Therefore, accurate fluid characterization is a vital part of any oil or gas production project. Advanced fluid-analysis techniques provide the high-quality data required to develop appropriate production strategies.

Discovery of an oil or gas accumulation immediately prompts questions about its economic viability. Operators want to learn about the extent of the reservoir, the types of fluids that would be produced, expected production rates and how long production might be sustained. Fluid analysis is a critical part of the process by which engineers perform reservoir characterization, determine the reservoir architecture and decide whether an oil or gas accumulation is worth developing. High-quality samples are essential, because erroneous data could lead engineers to misinterpret production parameters such as drainage volume, flow rates, reserves and facilities design and completion. Clearly, poor or misleading fluid data can have a severe negative financial impact.

If the reservoir analysis is positive, engineers begin designing a production system that will efficiently transport the reservoir fluids from the formation through wells, flowlines, production facilities and beyond. During this journey, reservoir fluids experience temperatures and pressures far different from their initial in-situ conditions. These variations may induce physical-state changes that would inhibit or interrupt production if not understood prior to designing tubulars and facilities. Therefore, to determine how the fluids will respond to production conditions, engineers may want to collect and analyze fluid samples from each potentially productive layer in the reservoir.

Traditionally, fluid samples are collected and sent to offsite laboratories for testing, a process that delays data access and impedes an operator’s ability to make time-sensitive development decisions. Today, sophisticated formation sampling and testing tools allow data collection

![Typical deepwater Gulf of Mexico oil-phase diagram. During the journey from the reservoir to the flowline, the oil temperature and pressure decline, and may cross phase boundaries at which asphaltenes (purple), waxes (blue) and hydrates (green) will tend to separate and form solid deposits. Gas begins to separate from the oil as it passes through the bubblepoint boundary (red).](image-url)
much earlier in the exploration process, including the ability to conduct real-time downhole Fluid Profiling characterization of reservoir-fluid properties and quantification of their variation. This technology gives operators the ability to evaluate the reservoir while the sampling tool is in the borehole, and acquire additional data if the reservoir is more complex than previously thought. In addition, engineers and fluid-property specialists can better determine where and when to sample, and how many samples to collect. As a result, the quality of fluid samples brought to surface is substantially improved.

In the laboratory, chemists determine fluid compositions, the temperatures and pressures at which phase transitions occur, and how each phase behaves as a function of temperature and pressure. Accurate fluid characterization and knowledge of pressure-volume-temperature (PVT) behavior are critical for making appropriate, cost-effective decisions about well planning, well construction, production and monitoring. When initial PVT screening and thermodynamic modeling identify nonstandard phase behavior (such as emulsions, wax or asphaltene precipitation, hydrates and scales), specialized testing is often performed to better understand reservoir-fluid behavior. All these activities fall under a general umbrella called flow assurance.

When confronted with potential flow-assurance problems, engineers have several ways to mitigate or prevent difficulties. These methods include thermal management (hot-fluid circulation, electrical heating and insulation), pressure management (pumping, boosting and blowdown) and chemical treatments. These techniques adjust the pressure-temperature path that hydrocarbons experience during production or, in the case of chemical treatments, alter the fluid composition to prevent phase changes or disperse solid particles when precipitation occurs. In addition, there are physical remediation techniques such as pigging, jetting and cutting.

As E&P companies venture into increasingly remote production environments, particularly deep water, flow assurance is critically important. Deepwater reservoir fluids follow a tortuous PVT path from the formation to the production facility, increasing the probability of flow-assurance difficulties (previous page). Flow assurance may also be a concern in arctic environments where thermal differences between the reservoir and surface facilities can be extreme. Accurate knowledge of PVT behavior is vital because reservoir-fluid problems in these remote locations could threaten the economic viability of a project.

This article describes the roles of chemistry, geology and thermodynamics during reservoir-characterization and flow-assurance studies at the wellsite and the laboratory. Also presented are two offshore-field case studies that demonstrate how these activities benefit well-completion design and operation.
Reservoir-Fluid Sampling

Scientists and engineers of various disciplines rely on fluid-sample data when making decisions about reservoir development. For example, reservoir engineers use the data to determine reservoir architecture, estimate reserves, perform material-balance calculations and analyze fluid flow in porous media. Geologists need accurate information to perform reservoir correlations and geochemical studies. Refining and marketing personnel make decisions about product yield and value. If erroneous data are used, unanticipated and expensive consequences could result during production.\(^1\)

A wide range of fluid behaviors can influence a sampling and analysis program. A reservoir-fluid system can be roughly categorized by its vapor-liquid phase behavior; the classifications range from dry gas, wet gas and retrograde gas to volatile oil, black oil or heavy oil (left).\(^1\) Another consideration is hydrocarbon solid-phase behavior. Wax and hydrate formation is predominantly induced by a temperature decline, and pressure reductions or fluid commingling generally cause asphaltenes to fall out of solution (next page, top).\(^3\)

Engineers collect formation-water samples to determine whether calcite, barite or halite scales will form within flowlines. Corrosive and toxic substances such as carbon dioxide \([\text{CO}_2]\) and hydrogen sulfide \([\text{H}_2\text{S}]\) must be detected and measured because they influence tubular-alloy selection and the design of safety and environmental systems from the wellhead to the surface production facility. Water pH is also an important parameter governing scale and corrosion, and may be measured downhole to avoid uncertainties.\(^5\)

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Another concern is the variability of reservoir-fluid composition within a field or formation. Petroleum reservoirs may consist of compartments that are isolated from one another. Independent flow elements may have an enormous impact on an operator's ability to drain the reservoir. As an analogy, consider a single reservoir compartment to be a sponge. Like a sponge with its open-cell structure, the entire contents can be drained by a single hole or well. Carrying the analogy further, independent reservoir compartments are similar to a spool of plastic bubble wrap—a closed-cell system through which the contents of one bubble cannot flow to another. If a single hole is punched through the spool, drainage occurs only from cells that are penetrated. The bubble-wrap spool is thus highly compartmentalized.

An additional consideration is the existence of large compositional variations of hydrocarbons vertically and laterally within a compartment. Compositional grading is often caused by gravity, or nonequilibrium forces of biodegradation, temperature gradients, current charging, charge history or incompetent sealing shales.\(^7\) The magnitude of compositional variation can vary greatly, depending on the geological and geochemical history of the reservoir (previous page, bottom)\(^8\).

A technically robust fluid-sampling program is vitally important when reservoir compartmentalization, compositional grading or both exist. Reservoir-formation properties influence the ability to collect representative fluid samples. Sample collection requires fluid flow into the borehole, which occurs only when the wellbore flowing pressure is lower than formation pressure. However, if the flowing pressure falls below the fluid saturation pressure, a gas phase (in the case of volatile or black oil) or a liquid phase (in the case of retrograde gas) will form (right). The relative mobility of each fluid phase is different; because of unequal flow, the composition of the fluid exiting the formation will not be the same as that in the reservoir. This effect can be minimized or eliminated by sampling at flow rates and pressure differentials that are as low as feasible.

Finally, accurate reservoir-temperature measurements are vital. Errors of just a few degrees during PVT testing could result in misinterpretation. For example, what is condensate in the formation may behave like a volatile oil at an incorrect temperature in the laboratory. This error could result in costly production-design errors.

\(^7\) Common deposits that form in tubulars during hydrocarbon production. Wax and hydrate deposition mainly result from a temperature decrease, while asphaltene precipitation may be triggered by changes in pressure, temperature and composition. Inorganic scales arise from changes in pressure, temperature and composition of aqueous fluids that accompany hydrocarbon production. (With kind permission of Springer Science and Business Media.)

\(^8\) Pressure-decline effects during reservoir-fluid sampling. If the reservoir pressure falls below the bubblepoint while sampling oil, gas separation will occur, creating a two-phase system (top). Similarly, if the reservoir contains retrograde gas, liquid will form if the reservoir pressure falls below the dewpoint. When phase changes occur in the reservoir, the high-mobility phase flows preferentially because of relative permeability effects, and the sample is nonrepresentative. Maintaining the reservoir pressure above the bubblepoint or dewpoint during sampling preserves single-phase behavior and ensures collection of a representative sample (bottom).
There are two principal hydrocarbon-sample acquisition methods—bottomhole and surface sampling. Bottomhole sampling involves conveying a sampling tool on a drillstem-test (DST) string, wireline or slickline to the producing zone in an open hole, sample the wellbore fluids for Fluid Profiling characterization and sample collection. The downhole LFA Live Fluid Analyzers provide real-time quantitative measurements of density, viscosity, GOR, hydrocarbon composition and formation-water pH.

There are two principal hydrocarbon-sample acquisition methods—bottomhole and surface sampling. Bottomhole sampling involves conveying a sampling tool on a drillstem-test (DST) string, wireline or slickline to the producing zone or zones. In an open hole, sample can be performed by the MDT Modular Formation Dynamics Tester and the Quicksilver Probe tool for focused extraction of pure reservoir fluid. Cased-hole sampling devices include the CHDT Cased Hole Dynamics Tester, single-phase reservoir sampler (SRS) and SCAR sampling tool. Surface sampling, which is most frequently performed at the separator under stable flow conditions, involves collecting gas and liquid samples. Engineers may acquire surface samples during exploration if downhole methods are unavailable, and may continue to do so throughout a well’s lifetime to monitor fluid-property evolution.

Bottomhole fluid samples must be extracted from locations that will yield the most relevant information for making decisions. To aid in this endeavor, today’s sampling and testing tools include an array of instruments that can perform downhole fluid analysis (DFA). DFA tools provide real-time fluid-property measurements at reservoir conditions, allowing engineers to analyze samples before they are gathered.

9. For more on formation-fluid sampling devices:


11. For more on optical DFA methods:


DFA methods include in-situ optical absorption spectroscopy, optical reflectance, fluorescence and some nonoptical measurements including density, viscosity and pH. The spectrometer operates in the visible to near-infrared range—at wavelengths between 400 and 2,100 nm. Spectra are recorded in real time, revealing the proportions of methane [C\textsubscript{1}], ethane to pentane [C\textsubscript{2}-C\textsubscript{5}], hexane-plus [C\textsubscript{6+}] and CO\textsubscript{2} fractions, as well as a gas/oil ratio (GOR) estimate. Additionally, differences between the reservoir-fluid and drilling-fluid spectra indicate the level of sample contamination.\textsuperscript{11} Downhole fluorescence measurements provide fluid-phase information that is especially useful for retrograde condensates and volatile oils.\textsuperscript{12} Fluorescence is also sensitive to liquid formation in a condensate gas when the flowing pressure falls below the dewpoint, allowing sampling engineers to monitor fluid-phase separation in real time, and ensure that representative single-phase samples are collected (previous page, top left).\textsuperscript{13}

Fluid Profiling reservoir-fluid characterization by DFA can diagnose compositional grading and help identify reservoir compartments. For example, abrupt fluid-composition or GOR changes between zones in a single well or between neighboring wells may indicate compartmentalization. To confirm that perceived fluid-property differences are truly significant, engineers must first consider measurement uncertainties. A recent method to evaluate uncertainties is the fluid comparison algorithm (FCA).\textsuperscript{14} FCA uses parametric models to estimate GOR and coloration uncertainties as a function of optical-density (\(\sigma_\eta\)) and mud-pollution (\(\sigma_\eta\)) measurement variability. The algorithm compares measurements acquired from two fluids and calculates the probability that differences are statistically significant. When the FCA result indicates that the fluids are different, sample acquisition for detailed surface analysis is justified. The following case study demonstrates how engineers employ DFA and FCA to characterize a reservoir and determine sampling locations.

**Sampling and Reservoir Characterization in a Deepwater Accumulation**

In a deepwater exploration well, Shell employed real-time DFA and FCA to characterize the reservoir architecture and decide where to collect fluid samples.\textsuperscript{15} As the MDT assembly traveled down the well, the spectrometers measured the GOR at several locations (previous page, top right). Based on FCA analysis, fluid samples were collected at 10 different depths. The analysis revealed wide variations in reservoir-fluid composition, ranging from dry gas and condensate gases at the top to black oils with different GORs at the bottom. At the bottom of the oil column, the GOR varied gradually with depth in the bottom sand, indicating a fluid-composition gradient. GOR inversions were also detected between the top and bottom sands, suggesting the presence of flow barriers and a complex reservoir structure.

DFA and FCA analysis showed that fluids above and below the inversion had a greater than 99% probability of existing in different compartments. A pressure discontinuity between the compartments confirmed the absence of hydraulic communication.

Shell and Schlumberger fluid specialists explored the oil column in detail, comparing the GOR information with petrophysical, formation-pressure and mud-gas logs, and performing FCA analysis (below). The gamma ray and pressure

![Expanded log presentation and FCA analysis of an oil column at the bottom of a deepwater reservoir.](https://example.com/image)
logs showed that the top portion of the oil resides in one sand lobe with a relatively constant GOR and pressure gradient. The rest of the oil is in a lower sand lobe, where the GOR decreases with depth. The pressure log was consistent, indicating a significant fluid-density difference between the upper and lower lobes.

Recent advances in mud-gas logging have given engineers another tool to perform real-time detection of seals and permeability barriers, lithological variations and fluid contacts. Gases gathered at the surface during drilling or separated from fluid samples can be analyzed for isotopic content. The isotopic signature, δ¹³C, is the value of the ¹³C/¹²C methane-isotope ratio in a sample relative to a standard, expressed in parts per thousand. When plotted alongside a standard mud-gas log, larger δ¹³C values may indicate higher concentrations of biogenic gas in the reservoir. Trending δ¹³C values may indicate nonequilibrium methane distributions, and a clear break in the methane-isotope signature in mud gas may imply the presence of a seal. Engineers noted a δ¹³C discontinuity at around 2,950 ft [899 m], suggesting yet another flow barrier. FCA analysis provided confirmation, calculating a 95 to 99% probability that fluids above and below the discontinuity were dissimilar and from different compartments with no communication.

The discovery of the fluid compartments in this deepwater field led Shell engineers to adjust their reservoir models and development planning. Reservoir compartmentalization increases design complexity and cost because engineers must treat each zone independently. Production forecasts, reserve calculations and enhanced recovery schemes became proportionately more complex.

Improved regional understanding of subsurface architecture impacted short-term decisions on sidetrack objectives. From the location of the borehole, Shell also reasoned that compositional grading in the lower reservoir likely extended downward from the penetrated zone; as a result, production-facility plans were altered to anticipate a GOR reduction with time.

Access to real-time fluid analyses allowed Shell to make decisions much earlier in the field-development process, and accelerated the project by at least six months. At today’s oil prices, the time saved was worth hundreds of millions of dollars.

**Laboratory Fluid Preparation and Sample Chain of Custody**

The preceding case study demonstrates the considerable effort and care that engineers apply during the sampling process. Nevertheless, the harsh downhole environment and the nature of well operations may render DFA equipment, sampling devices and subsequent analysis susceptible to fouling, failure and other inaccuracies.

Schlumberger engineers addressed this problem by implementing a chain-of-custody procedure, a concept borrowed from forensic science. Evidence must make the journey from a crime scene to the courtroom in a validated and secure manner; otherwise, it may not be admissible in court. Similarly, chemists at a remote testing laboratory should be able to determine whether the chemical composition of a field sample has been preserved. DFA provides a convenient way to establish a chain of custody for fluid samples, because chemists have the opportunity to compare analytical data acquired downhole with those from the corresponding samples that reach the laboratory.
In the field, after tool retrieval, engineers remove the reservoir-fluid samples. At this point, a PVT Express onsite well fluid analysis system may be available to conduct preliminary measurements that determine whether the collected-sample properties agree with those measured by DFA.19 If onsite analysis is unavailable or more sophisticated testing is required, the samples are shipped to a remote testing laboratory in the original sample bottles or transferred to an approved shipping container. When fluid samples arrive at the Schlumberger laboratory, chemists restore the fluid inside the sample container to the original reservoir temperature and pressure, and allow the fluid to equilibrate by agitating it continuously for up to five days. The restoration process is intended to redissolve precipitated asphaltene and wax particles, ensure a homogeneous fluid throughout the sample cylinder and provide a single-phase representative fluid for testing.

The visible near-infrared (IR) spectrum is an effective hydrocarbon fingerprint.20 The DFA spectrometer performs sample analysis as the crude-oil sample is acquired, providing a direct fluid-property measurement under downhole conditions. In the laboratory, chemists perform the same measurement with a research-grade spectrometer at the downhole temperature and pressure. Differences between the DFA and laboratory spectra may indicate that the laboratory sample has been compromised. For example, if the methane concentration is lower in the laboratory spectrum, then sample-bottle leakage or a fluid-transfer error may have occurred during sampling or transport to the laboratory. The examples presented below illustrate the chain-of-custody technique.

The first example involves a fluid sample acquired from an offshore oil field. There is excellent agreement between the downhole and laboratory spectra (previous page). This indicates that the sample is well-preserved and suitable for further laboratory studies.

The second example involves another sample from an offshore oil field (right). The downhole and laboratory spectra have good overall agreement, but there are subtle differences in the wavelength region above about 1,600 nm. The calculations showed that the GOR from the downhole spectrum, 580 ft³/bbl [103.3 m³/m³], was significantly higher than that from the laboratory spectrum, 320 ft³/bbl [57.0 m³/m³]. This difference corresponded to a chain-of-custody investigation of a compromised crude-oil sample. Both spectra were measured at downhole conditions—20,000 psi [138 MPa] and 200°F [93°C]. The visible near-IR spectral analysis (top) shows subtle OD differences in the region above about 1,600 nm. At 1,671 nm, indicating methane, the laboratory-sample OD is lower than that measured by the LFA tool. At 1,725 nm, the methylene “oil peak,” the laboratory sample OD is higher than that measured by the LFA tool. These differences are also visible in the linear regression plot (bottom). The ratio between the methane and oil peaks can be used to calculate the GOR. In this case, the algorithms indicated that the laboratory-sample GOR was significantly lower than that of the field sample. Therefore, further analysis would be necessary before this sample could be trusted.

20. For more on visible and near-IR spectroscopy: Cramb et al, reference 11.
93% likelihood that either one (or both) of the spectra were in error, or the laboratory sample was compromised. Further investigation of surface procedures and DFA-tool performance would be required before this sample could be used with confidence in the laboratory.

**Laboratory Techniques for Flow Assurance**

In the laboratory, chemists determine fluid compositions and measure fluid properties related to flow assurance. For compositional analysis, an accurately measured volume of fluid is isobarically and isothermally transferred to a pycnometer to measure mass and density. Then, the pycnometer is connected to an apparatus in which the oil sample is cooled to ambient temperature and decompressed. The volume of gas liberated by this procedure allows calculation of the GOR.

Chemists employ gas chromatography to determine the vapor-phase composition up to C15+ and the liquid-phase composition up to C36+. The bulk crude-oil composition is calculated by summing the individual contributions from each phase (above left). This procedure ensures that a consistent reservoir-fluid composition is available for subsequent fluid-property characterization and reservoir-production simulation.

The bubblepoint pressure is determined by performing a constant composition expansion (CCE) test. Technicians place a known volume of equilibrated fluid in a PVT cell at reservoir temperature and pressure (left). The fluid is initially single phase, and testing begins by reducing the pressure isothermally and monitoring the fluid-volume change. Eventually, the fluid separates into two phases. Pressure reductions continue in increments ranging from 100 to 500 psi [0.69 to 3.45 MPa], the vapor and liquid phases are equilibrated at each step, and phase volumes are measured and plotted as a function of pressure. For a black oil, the intersection of the single- and two-phase lines in the PV plot defines the bubblepoint.

The flow-assurance testing protocol depends on the nature of the crude oil. For example, when asphaltenes are of concern, then saturate, aromatic, resin and asphaltene (SARA) analysis and paraffinic solvent titration with dead oil are principal screening techniques.22 It is also common to measure the asphaltene-precipitation pressure on a live-oil sample. If testing identifies an asphaltene-precipitation problem, additional studies are conducted to map out the asphaltene phase diagram and evaluate the effectiveness of chemicals or coatings as prevention strategies.23
Waxy crude oils pose different production and transportation challenges. Wax deposition inside tubulars and pipelines reduces the effective flow area, increasing the pressure drop and potentially causing complete blockage. Therefore, it is important to fully understand the oil’s behavior throughout the pressure and temperature path from the formation to the production facilities. Temperature is the dominant parameter affecting waxy crude-oil viscosity, gel strength, pour point, wax crystallization and deposition. Although dead oils such as stock-tank oil (STO) can be used to generate preliminary data, it is important to include live oils in the testing program because pressure and dissolved gases may strongly influence wax solubility.

The first characterization step is to measure the amount of wax that can precipitate and deposit on a solid surface. Live-oil filtration and high-temperature gas chromatography (HTGC) are common methods to measure the wax content. HTGC is more valuable because it provides the n-paraffin composition at high carbon numbers (from C_{60} to C_{100})—information chemists enter into thermodynamic models to predict wax behavior.

The wax-appearance temperature (WAT) is one of the most important flow-assurance measurements, indicating the temperature at which wax crystals begin to form in a crude-oil sample. This measurement provides a preliminary assessment of the likelihood of wax-related deposition problems. Laboratory workers place dead oil on the stage of a cross-polar microscope (CPM) and block light transmission by adjusting polarized prisms at opposite ends of the sample. When illuminated by polarized light, crystalline materials disturb the polarization plane; therefore, as the fluid sample cools, wax-crystal formation is clearly visible as bright spots appear against the black background (above right). Some laboratories have high-pressure CPM instruments that can measure the WAT in live oils. The sample cell operates at pressures up to 20,000 psi [138 MPa] and temperatures up to 392°F [200°C].

Formation and growth of wax crystals may affect the rheological behavior of the crude oil. Above the WAT, most hydrocarbon systems behave as Newtonian fluids; however, non-Newtonian behavior such as shear thinning may commence as the fluids cool and phase changes occur. This behavior must be properly quantified to allow engineers to design a suitable production system. Rheological properties of interest in the context of waxy crude are pour point, apparent viscosity and gel strength.

The pour point is the temperature below which a fluid is no longer pourable because of viscousification, gelation or solids formation. Pour-point testing with dead oils conforms to ASTM Standard D97. For live oils, engineers use an apparatus containing a visual sapphire cell mounted on an automatic, vibration-free pivoting bracket that resides in a programmable convection oven. The oil sample is heated to the reservoir temperature, and slowly cooled until fluid movement in the cell ceases. Most waxy crude oils begin to display non-Newtonian behavior near the pour point. If the pour point exceeds anticipated oil-production temperatures, engineers may add pour-point-depressant chemicals to maintain flow.

The apparent viscosity of waxy crude oils generally increases dramatically as the temperature and shear rate decrease, particularly at temperatures near the pour point. Schlumberger engineers measure viscosity with a rheometer that can operate at 6,000 psi [41.4 MPa] and 302°F [150°C], allowing work with live oils.

Waxy crude oils tend to form gels at temperatures below the pour point. In the event of a production shutdown, high pumping pressures may be required to break the gel and restore flow. Therefore, yield-stress data from waxy crude oils are necessary to properly design flowlines and avoid production problems. The
yield stress of live fluids can be determined by a model pipeline test (MPT) (left)\(^\text{26}\).

Another important measurement in the context of production-system design and flow assurance is the wax-deposition rate. The principal controlling parameters are fluid temperature, heat loss through the pipeline wall, wax content, shear rate and fluid viscosity. The wax-deposition rate can be determined under simulated pipe-flow conditions in a wax-deposition flow loop (WDFL) (below left).

The following case study illustrates how operators use laboratory measurements to develop operational strategies that prevent, mitigate or remediate wax deposition and gel formation.

Optimizing Subsea System Design in West Africa

A West African field, located at a water depth less than 1,000 ft [300 m], has a reservoir temperature and pressure of 170°F [76.7°C] and 3,180 psi [21.9 MPa]. The seabed temperature is 55°F [12.8°C]. The operator planned to produce oil through a looped 6-in. ID subsea tieback to a host facility 2 miles [3.2 km] from the reservoir. With the large temperature difference between reservoir and seabed, and the long distance that fluids would flow along the cold seafloor, the operator needed assurance that solids deposition would not impede flow. Schlumberger collected downhole fluid samples and sent them to the Oilphase-DBR fluid sampling and analysis laboratory in Edmonton, Alberta, Canada for a flow-assurance study\(^\text{27}\).

Compositional analysis of the reservoir fluid revealed a black oil with a GOR of 230 ft ³/bbl [41.0 m ³/m³] and an API gravity of 36.3. Compositional analysis indicated that the fraction with a carbon number above C\(_{30}\) was 35.8%. Further characterization of the C\(_{30+}\) fraction and n-paraffin distribution revealed that the crude oil contained about 13.1 wt\% C\(_{17+}\) n-paraffins.\(^\text{28}\) The relatively high n-paraffin concentration was cause for concern that the

\(^\text{26}\) The yield stress, \(\tau_y\), is calculated by the following force-balance equation:

\[
\tau_y = \frac{P_D}{4L} \nonumber\]

where \(P_D\) is the hydraulic pressure necessary to cause fluid movement, \(D\) is the inner diameter of the coil and \(L\) is the coil length.


\(^\text{28}\) Paraffin is a common name for a group of alkane hydrocarbons with the general formula C\(_n\)H\(_{2n+2}\), where \(n\) is the number of carbon atoms. The simplest paraffin molecule is methane, CH\(_4\), a gas at room temperature. Octane, C\(_{8}\)H\(_{18}\), is liquid at room temperature. The solid forms of paraffin are heavier molecules from C\(_{20}\) to C\(_{40}\). Linear members of the series (those with no branches or cyclic structures) are called n-paraffins.
fluid might exhibit flow-assurance problems related to wax deposition. Therefore, the Oilphase-DBR team objective was to generate measurements that would provide guidance concerning ways to mitigate and remediate wax deposition during steady-state and transient events during crude-oil production.

Constant composition expansion (CCE) testing measured a bubblepoint pressure of 700 psi [4.8 MPa] at the reservoir temperature. WAT and pour-point tests were performed with both live- and dead-oil samples (right). As the fluid pressure fell below the bubblepoint to ambient conditions, dissolved gas escaped, the average sample composition shifted toward heavier hydrocarbons, and both the WAT and pour point increased approximately 20°F [11.1°C].

Rheological testing revealed gel-structure formation in live crude oil at low shear rates when the fluid temperature fell below the pour point and approached the seabed temperature (below). As the rheometer pressure decreased, the shear stress required to break the gels increased—behavior consistent with the loss of lighter hydrocarbons. Around the pour point,
shear-thinning behavior with no gelation occurred at all pressures. Further investigation of gel strength involved aging live- and dead-oil samples for 12 hours at the seabed temperature. The live-oil gel strength between 100 and 700 psi varied from 38 to 42 Pa, and the dead-oil gel strength at ambient pressure was more than three times greater—142 Pa.

Dead-oil wax-deposition tests were conducted in the WDFL at temperatures between 81° and 122°F [27.2°C and 50.0°C] (top). The results revealed a deposition-rate discontinuity at the higher end of the shear-rate range. For each shear rate, chemists entered the measured deposition rates, the n-paraffin distribution, C_{30+}, composition and viscosity profile into a standard equation-of-state model that calculates an n-paraffin diffusion coefficient. The model assumes that molecular diffusion of wax molecules is the principal driving force governing wax deposition.⁷

The next step involved entering the flow-assurance measurements, wax-deposition data and diffusion coefficients into the OLGA simulator—a commercial multiphase-flow fluid-transport model—to assess and predict crude-oil behavior in various production scenarios. Schlumberger engineers applied OLGA simulations to two cases: producing at a steady state and restarting production after a shutdown.

Because the WAT of the West African crude oil was about 50°F [27.7°C] higher than the pour point, wax deposition and gel formation were the principal flow-assurance risks during steady-state production. The operator’s design goal was to prevent wax deposition at production rates above 5,000 bbl [795 m³] of oil per day. Methods to prevent or slow wax deposition in a pipeline include using insulated pipe, installing heaters and injecting paraffin inhibitors into the crude-oil stream. OLGA simulations determined that pipe insulation was the most suitable flow-assurance method (next page). Having both live- and dead-oil data proved important. Knowing only the dead-oil WAT would have led the operator to believe that expensive pipe-in-pipe insulation was necessary. Calculations using the lower live-oil WAT showed that more economical wet insulation would be sufficient to prevent wax deposition.

Because the oil cools as it flows through the pipeline to the collection facility, it was essential to predict the likelihood of gel formation. Assuming a production rate of 5,000 bbl/d through wet insulated pipe, the OLGA simulator showed that live oil could flow through the pipeline for about 20 hours before reaching its pour point—sufficient time to reach the stock tank.

For flow rates less than 5,000 bbl/d, the OLGA simulator predicted rates at which wax deposition would occur in the pipeline. Without experimental WDFL wax-deposition data, engineers would have to use the standard model to estimate the n-paraffin diffusion coefficient, predict a deposition rate, and schedule wax-removal operations. For this West African crude oil, the standard model predicted that remediation would be necessary every two weeks. With WDFL data, the simulator predicted a much lower deposition rate, increasing the time between remedial jobs to six weeks. Methods to remove wax deposits include pipeline pigging.
hot-oil circulation and solvent treatments with coiled tubing.

A vital flow-assurance question concerns the ability of the system to restart after a production shutdown. According to the operator, 500 psi was the highest pressure that could be safely applied to overcome gel strength and initiate flow (previous page, bottom). Using live-oil gel-strength data and fluid-transport parameters, the OLGA simulator calculated that fluid flow could be restored as long as the pressure in the pipeline remained above about 100 psi.

This case study shows that reliance on dead-oil experimental data and standard wax-deposition calculations could lead operators to make unduly conservative decisions when designing production systems. In this case, flow-assurance predictions based on live-oil data allowed the operator to save millions of dollars in flowline costs and less frequent wax-removal operations.

### Coming Advances in Waxy-Crude Flow Assurance

Significant work is underway to continue improving flow-assurance testing and fluid-property surveillance during a field’s productive life. The West Africa case study demonstrated the benefits of performing flow-assurance experiments with live crude oils. However, wax-deposition testing in devices like the WDFL has been confined to dead oils. The WDFL could be modified to perform high-pressure tests, but consuming two liters of live oil would be prohibitively expensive.

Oilphase-DBR scientists overcame this problem by designing and introducing the RealView live solids deposition cell. 29 Requiring only 0.04 gal US [150 mL] of oil, the cell can operate at pressures up to 15,000 psi [103.4 MPa], temperatures up to 392°F and Reynolds numbers up to 500,000. 30 Unlike the WDFL, the oil resides in a cylindrical vessel. A rotating spindle at the center induces fluid movement. The device can simulate production conditions of temperature, pressure, composition, pipe-surface roughness and both laminar and turbulent flow. Turbulent-flow testing is useful

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31. In fluid mechanics, the Reynolds number is a dimensionless ratio of inertial forces to viscous forces. Turbulent-flow conditions exist when the Reynolds number exceeds 3,000.
The results showed that wax-deposition behavior of waxy crude oil in the WDFL and RealView live solids deposition cell. Turbulent flow in the RealView cell reduced the dead-oil deposition rate substantially. Live-oil deposition rates in the RealView apparatus were even lower for both flow regimes.

The low wax-deposition rates observed with live oils would significantly impact the hypothetical flow-assurance situation. Oilphase-DBR scientists assumed the oil entered a 6-in. ID, 2-mi long pipeline at a temperature and pressure of 170°F and 3,170 psi [21.9 MPa]. The simulated oil-production rate was 5,000 bbl/d, and the seabed temperature was 65°F [18.3°C]. Within this scenario, engineers performed deposition-rate tests that compared the performance of STO and live oils in laminar and turbulent flow (above right). The results showed that wax deposition is slower in turbulent flow, and live-oil wax-deposition rates are far lower than those observed with STO.

The field produces, the crude-oil properties can change because it simulates the shear environment at the flowline wall (above). Thanks to live-oil testing in the RealView cell, significant advancements in asphaltene flow assurance have already been realized.

Preliminary laboratory results show that live-oil testing will lead to similar improvements for waxy crude oils. A recent laboratory study tested the behavior of a black waxy crude oil in a hypothetical flow-assurance situation. Oilphase-DBR scientists assumed the oil entered a 6-in. ID, 2-mi long pipeline at a temperature and pressure of 170°F and 3,170 psi [21.9 MPa]. The simulated oil-production rate was 5,000 bbl/d, and the seabed temperature was 65°F [18.3°C]. Within this scenario, engineers performed deposition-rate tests that compared the performance of STO and live oils in laminar and turbulent flow (above right). The results showed that wax deposition is slower in turbulent flow, and live-oil wax-deposition rates are far lower than those observed with STO.

The low wax-deposition rates observed with live oils would significantly impact the hypothetical flowline design and the frequency of wax-removal operations. OLGA simulations demonstrated that the 2-mi flowline could be constructed from foam-insulated pipe instead of pipe-in-pipe, potentially saving US $4 million. In the context of flowline remediation, traditional WDFL measurements with STO indicated that wax removal would be necessary every two weeks. Simulations with live-oil data predicted that wax removal would be necessary about once per year, providing significant operational savings.

As a field produces, the crude-oil properties often change. For example, as gas condensate falls below the saturation pressure during depletion, the condensate yield and the WAT may fall. In a compositionally graded accumulation, composition may change as fluids are produced from regions that were originally distant from the initial sampling point. The impact on flow assurance may be significant.

Traditionally, engineers monitor fluid-property evolution by periodically sampling from separators or extracting live oil near perforations, and performing flow-assurance tests in the laboratory. In offshore and deepwater fields, this approach is costly. With the advent of intelligent completions, equipped with sensors that transmit downhole temperature, pressure and flow rates in real time, production monitoring can be performed remotely. These completions also incorporate remote-control pumps and valves that engineers can use to mitigate flow-assurance problems.

Chemical sensors are being developed that can detect fluid-composition changes. When installed at strategic locations in the well completion and along a pipeline, the sensors will provide real-time data for monitoring of solids deposition, corrosion rates and rheological properties. As a result, interventions for sampling or remediation will be performed only when necessary.

Today, fluid sampling and analysis are progressing to a point at which consistent standards are applied along the continuum from DFA and reservoir characterization, to sampling and laboratory analysis, and on to production surveillance. This integrated approach will be increasingly valuable to operators making reservoir exploration, development and production decisions, particularly in high-risk, remote locations.

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Wax-deposition behavior of waxy crude oil in the WDFL and RealView apparatus. Engineers performed tests with dead and live oils. In laminar flow, dead-oil wax-deposition rates were essentially the same in the WDFL and the RealView cell. Turbulent flow in the RealView cell reduced the dead-oil deposition rate substantially. Live-oil deposition rates in the RealView apparatus were even lower for both flow regimes.