

Core Truth in Formation Evaluation

The nature of subsurface exploration forces oil and gas companies to investigate each reservoir remotely, primarily through well logs, seismic surveys and well tests. Through analysis of rock samples obtained downhole, core laboratories provide a wealth of information about lithology, porosity, permeability, fluid saturation and other properties to help operators better characterize the complex nature of the reservoir.

Mark A. Andersen
Brent Duncan
Ryan McLin
Houston, Texas, USA

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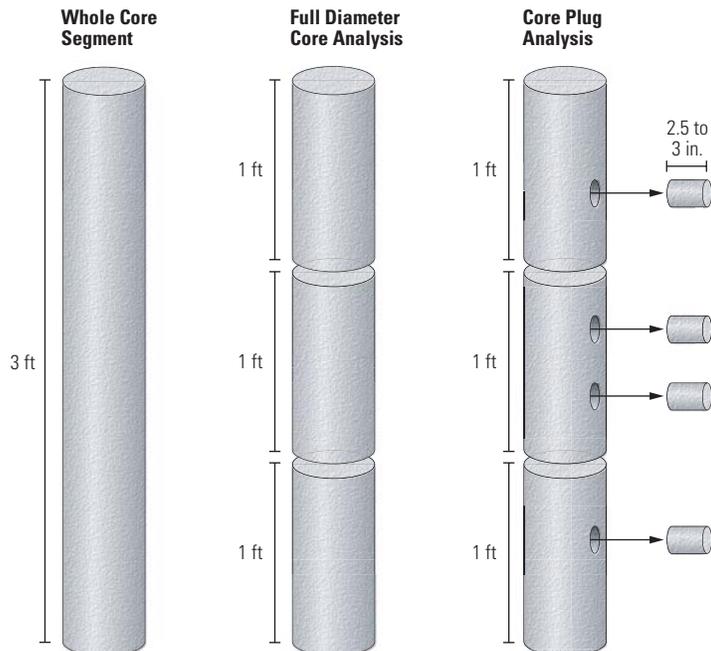
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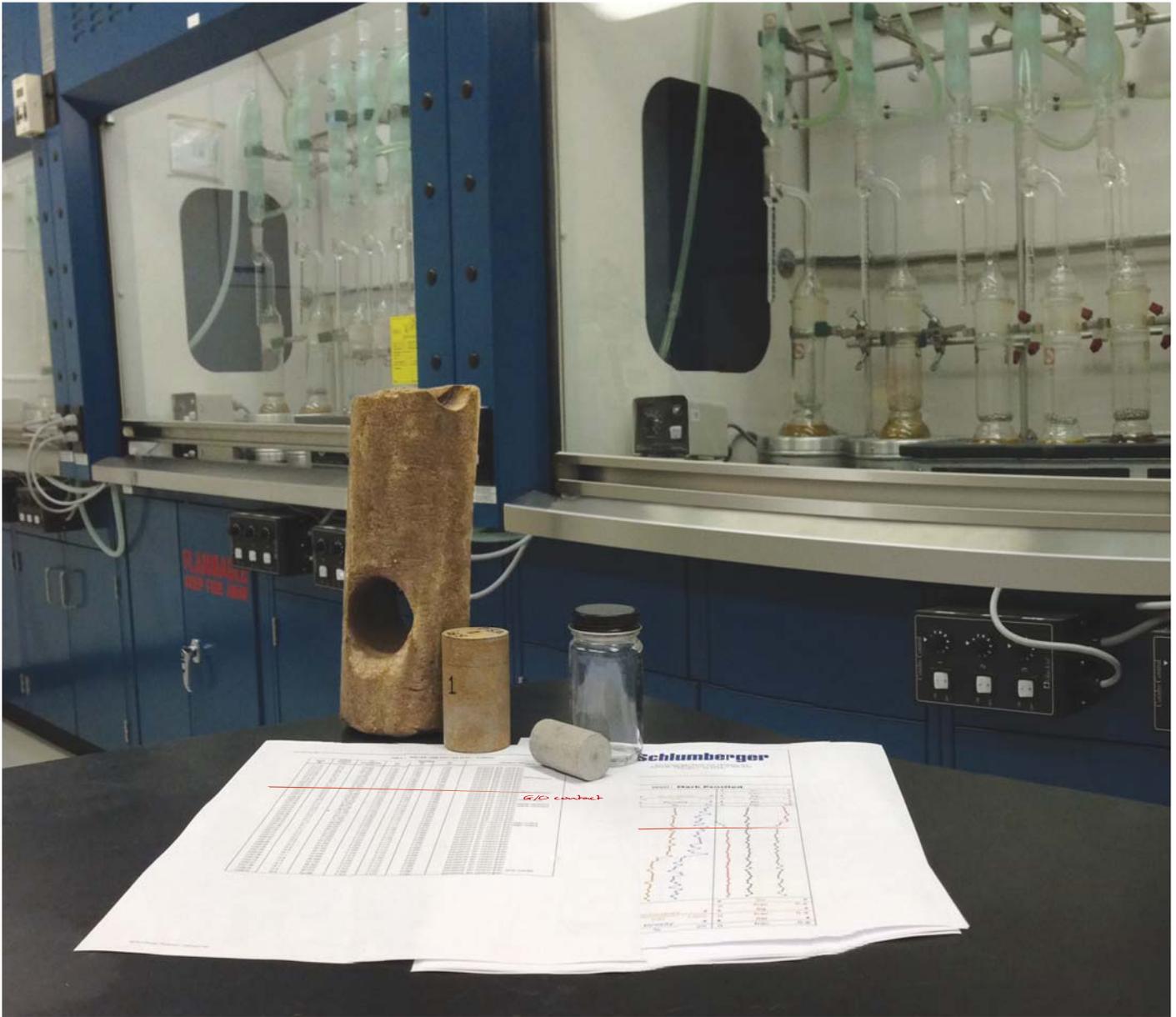
Cores provide essential data for the exploration, evaluation and production of oil and gas reservoirs. These rock samples allow geoscientists to examine firsthand the depositional sequences penetrated by a drill bit. They offer direct evidence of the presence, distribution and deliverability of hydrocarbons and can reveal variations in reservoir traits that might not be detected through downhole logging measurements alone. Through measurement and analysis of porosity, permeability and fluid saturation from core samples, operators are better able to characterize

pore systems in the rock and accurately model reservoir behavior to optimize production.

Core analysis is vital for determining rock matrix properties and is an important resource for formation characterization. The process known as routine core analysis helps geoscientists evaluate porosity, permeability, fluid saturation, grain density, lithology and texture. Routine core analysis laboratories (RCALs) frequently provide a variety of additional services such as core gamma logging for correlating core depth with wellbore logging depth, core computed tomography (CT) scans for



^ Divided cores. At the wellsite, whole cores are typically cut into smaller segments for ease of shipping. At the laboratory, the whole core segments may be cut and subsampled.



characterizing rock heterogeneity and core photographs for documenting and describing the core.

When operators need to understand complex reservoir behaviors, they turn to special core analysis for detailed measurements of specific properties. Special core analysis laboratories (SCALs) are typically equipped to measure capillary pressure, relative permeability, electrical properties, formation damage, nuclear magnetic resonance (NMR) relaxation time, recovery factor, wettability and other parameters used for calibrating logs. SCAL services are also used to characterize reservoirs for enhanced oil recovery (EOR) and for studying multiphase flow and rock-fluid interactions. Only a few samples are selected for these extensive tests, some of which require weeks to complete.

For years, Schlumberger has maintained a number of core analysis laboratories to support research into wireline tool response, drilling fluid chemistry, formation damage, EOR or completion technology. However, these facilities did not provide core analysis on a commercial scale. Until recently, the company's commercial core analysis services were centered in Salt Lake City, Utah, USA, where the TerraTek rock mechanics and core analysis facility is known for its focus on geomechanics and unconventional reservoirs. The 2012 inauguration of Schlumberger Reservoir Laboratories has opened the way for integrating rock measurement technologies with fluids expertise to help customers better understand reservoir behavior. Schlumberger now offers rock and fluid analysis through 27 laboratories around

the globe. Several companies offer similar analyses of conventional cores. This article focuses on routine analysis of conventional sandstone and carbonate cores carried out by specialists at the Schlumberger Reservoir Laboratory in Houston.

Sample Sizes

Cores come in a variety of lengths and diameters ([previous page](#)). The information extracted from a core depends in part on the size and quantity of the core, which control the types of analyses that may be performed. To meet customer needs, the core analysis laboratories must be flexible enough to process the various types of core sent from the wellsite, be they bottomhole cores or sidewall cores.

Bottomhole cores, also referred to as whole cores, or conventional cores, are obtained during the drilling process using a special coring bit (below). The cores typically range in diameter from 4.45 to 13.3 cm [1.75 to 5.25 in.] and are generally drilled in 10-m [30-ft] increments, which correspond to the length of the core barrel or its liner. Whereas a conventional bit is designed to grind away the rock at the bit face, the doughnut-shaped coring bit creates a cylinder of rock that passes through the center of the bit and is retained in a protective core barrel.

When the core barrel is full, the driller pulls the assembly out of the hole, and a wellsite coring specialist lays the barrel liner on the pipe rack. The liner, with core inside, is then scribed with depth markings and orientation lines. For ease of shipping, the metal liner is usually cut into 1-m [3-ft] segments and sealed at each end. To prevent shifting during transit, the wellsite core-handling team may inject epoxy or foam into the liner to stabilize the core.

For sidewall cores (SWCs), the process is far less involved. SWCs are obtained by a wireline sampling device, which is typically run in the hole near the conclusion of an openhole wireline logging job after the operator consults the logs to

identify zones that merit sampling. The SWC device can extract up to 90 samples from the side of the wellbore at selected depths. Once on the surface, sidewall cores are retrieved from the tool, sealed in individual bottles and shipped to the laboratory for analysis.

Percussion-type sampling devices obtain SWCs measuring from about 2.86 to 4.45 cm [1.125 to 1.75 in.] in length by 1.75 to 2.54 cm [0.688 to 1 in.] in diameter. Percussion sampling devices are known as core guns because they use small explosive charges to propel individual core barrels, called bullets, into the formation. The core barrels are attached to the gun with strong cables that are used to pull the core bullet from the borehole wall as the gun is reeled uphole. By contrast, rotary cores are cut from the formation using a miniature, horizontally oriented coring bit. The XL-Rock large-volume rotary sidewall coring tool can drill cores 6.4 cm [2.5 in.] long by 3.8 cm [1.5 in.] OD from the side of the borehole. This device produces core samples that have more than three times the volume of percussion SWCs.

A third type of rock sample is the core plug. The core plug is extracted from segments of whole core. These plugs are taken as a representative subsample of the whole core and are useful

in analyzing intervals of relatively homogeneous core. Core plugs in conventional reservoirs are routinely taken at 0.3-m [1-ft] intervals along the length of the core and measure about 6.4 cm long by 2.54 or 3.8 cm in diameter. Variations in lithology may require smaller sampling intervals, but if the core is highly heterogeneous, as seen in vugular or fractured carbonates or thinly laminated sand-shale intervals, the operator may elect to analyze the whole core rather than plugs.

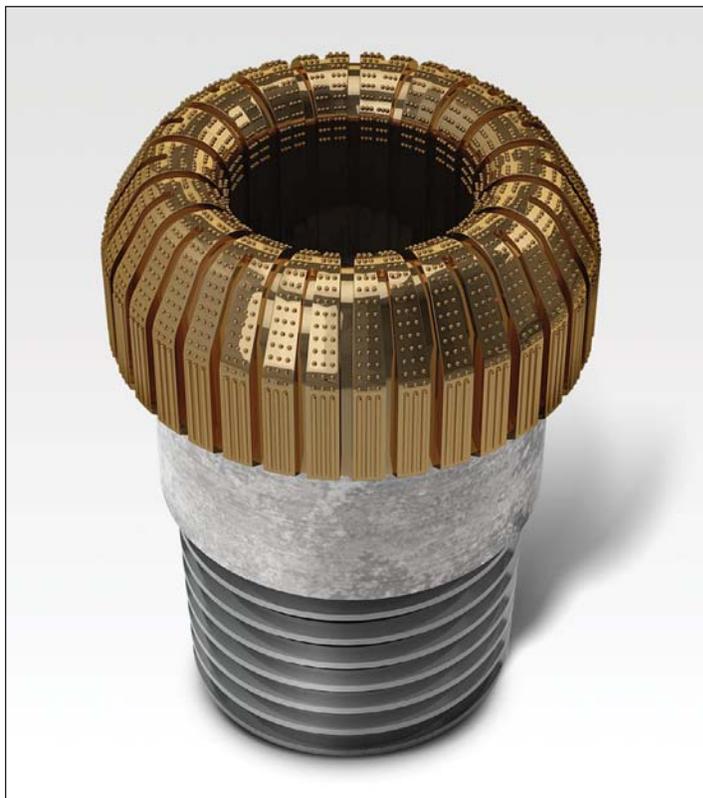
Initial Processing

The basic workflow for conventional core analysis moves from receiving to preliminary imaging, then to preparation and analysis. Each process involves several steps. Whole cores typically require more initial processing than sidewall cores. Although routine core analysis provides a standard set of measurements, not all cores go through the entire workflow described here.

At the laboratory, cores are received and inventoried. Whole cores are run through a core gamma ray logger, which measures gamma rays that are naturally emitted from the cores. By comparing core gamma ray measurements to LWD or wireline gamma ray logs, geoscientists can correlate core depth to log depth and identify intervals from which core may have been lost or damaged.

The core gamma ray logging device uses a conveyor to move the core—either exposed or sealed within the liner—past a gamma ray detector. The detector scans the core along its length from bottom to top, which replicates the logging sequence used in obtaining wireline logs.

Next, the core is run through a computed tomography scanner to obtain a CT image. The CT device obtains a 3D image of the whole core, taking a series of closely spaced scans that can be sliced at any point or orientation to create a virtual slab of the core. The CT scanner permits a quick reconnaissance across the core. When zones of interest are identified, they may be scanned again for detailed examination (next page). CT scanning is especially useful for detection and evaluation of internal features such as bedding planes, vugs, nodules, fossils and frac-



▲ Coring bit. This polycrystalline diamond compact (PDC) bit employs a fixed cutter design that leaves the center of the borehole untouched. The bit creates a cylindrical core of the formation that passes through the middle of the bit, to be retained within the bottomhole assembly.

1. For more on CT scans in oilfield applications: Kayser A, Knackstedt M and Ziauddin M: "A Closer Look at Pore Geometry," *Oilfield Review* 18, no. 1 (Spring 2006): 4–13.
2. Passey QR, Dahlberg KE, Sullivan KB, Yin H, Brackett RA, Xiao YH and Guzmán-García AG: "Digital Core Imaging In Thinly Bedded Reservoirs," in Dahlberg KE (ed): *Petrophysical Evaluation of Hydrocarbon Pore-Thickness in Thinly Bedded Clastic Reservoirs*. Tulsa: The American Association of Petroleum Geologists, AAPG Archie Series, no. 1 (June 30, 2006): 90–107.
3. Perarnau A: "Use of Core Photo Data in Petrophysical Analysis," *Transactions of the SPWLA 52nd Annual Logging Symposium*, Colorado Springs, Colorado, USA, May 14–18, 2011, paper Z.

tures.¹ Operators occasionally specify that sidewall cores be scanned as well. CT scans are noninvasive, require no further preparation of the core and can be performed rapidly on exposed cores or on cores retained inside the core barrel.

After performing initial scanning, the core analyst frees the core from the barrel to prepare it for further testing. The analyst uses a band saw or radial saw, equipped with a diamond-impregnated blade, to cut the core lengthwise—parallel to the core axis—into slabs. In most cases, the core is cut off center rather than sliced down the middle. The thickness of the slab dictates the maximum size of any plugs subsequently sampled from the core. The flat face of the thinner slab is polished to remove saw marks in preparation for slab photography.

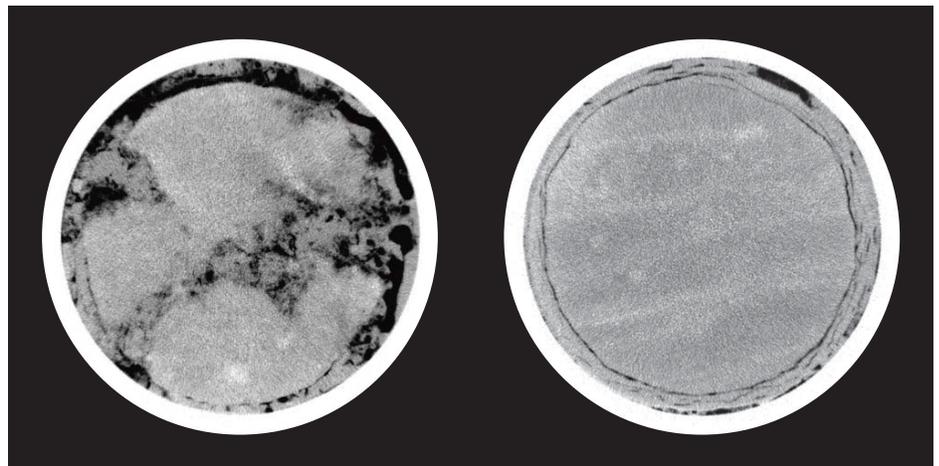
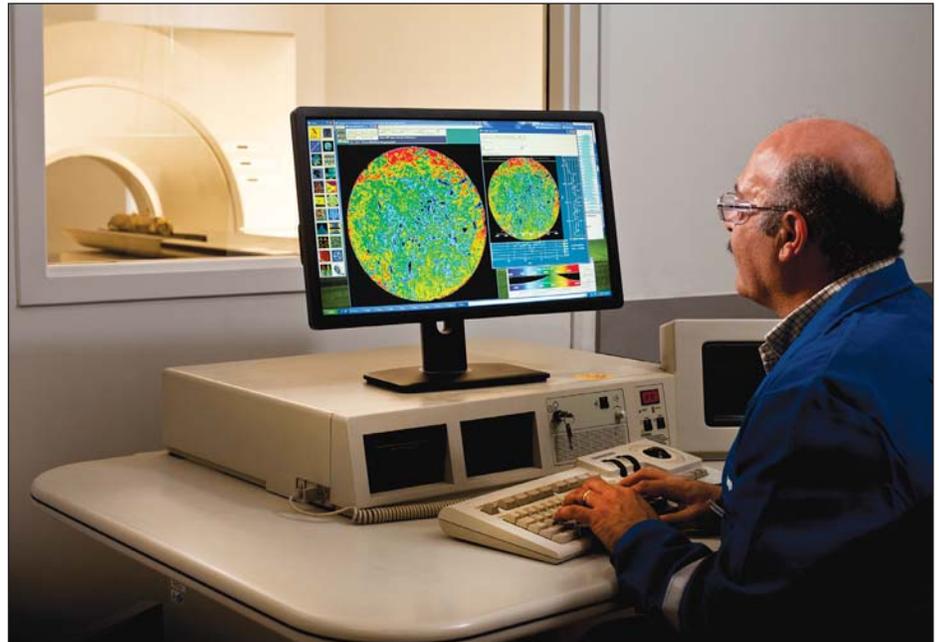
In some cases, portions of the core are not slabbed. When a core exhibits substantial, large-scale heterogeneity—typical of vuggy carbonates or severely fractured or conglomeratic rock—then sections of the core may be set aside without slabbing to permit analysis of the full diameter core.

The core slabs are photographed using a 35-mm digital camera linked to a dedicated computer, which can digitize, display and transmit images to the client. Photographs can often resolve individual layers within thin beds measuring just tenths of an inch.

Digital photography helps highlight important geologic and petrophysical characteristics. These high-resolution color images provide an important visual record of lithology, bedding characteristics, contacts, fractures, fossils, porosity, vugs and sedimentologic variations that may be studied in detail—long after the core has been subjected to further testing. Subsequent manipulation and analysis of core images often yield valuable information not readily apparent from the original photographs. In some cases, they can be used to reconcile discrepancies between core and log analysis, detecting formation laminations that are too thin to be resolved by the logging tool.

Upon client request, a 360° axial wrap of the core is imaged. This is accomplished using a digital camera and a table with rollers that rotate the full diameter core longitudinally as it is photographed.

Photographs are taken in white and in ultraviolet (UV) light. Images shot in plain white light show the cores under natural lighting conditions. The UV light may highlight certain types of minerals but, more importantly, it can enhance the contrast between nonreservoir and oil-bearing zones. Oil-bearing reservoir rocks frequently exhibit strong ultraviolet fluores-



^ Whole core CT scans. Pore characteristics are brought into sharp focus in a virtual slice of core (*top*, foreground) as the sample passes through the CT scanner (*top*, background). Color coding on the scan helps distinguish regions of differing density or mineralogy. By contrast, grayscale images are used to highlight core damage. A core obtained through a friable formation at the Casabe field in Colombia was scanned prior to being removed from the core liner (*bottom*). Stacks of cross sections revealed areas where portions of the core were damaged. The white exterior ring is the core liner; a layer of caked drilling mud inside the liner surrounds the core. By avoiding fractured intervals (*bottom left*), the core analyst was able to select undamaged sections (*bottom right*) from which to extract plugs. (CT images courtesy of Carlos Chaparro and Adriano Lobo, Ecopetrol, Bogotá, Colombia.)

cence. Typically, an oil emits fluorescence, the brightness and color of which are affected by its composition. However, some oils do not fluoresce. Furthermore, if flushing has removed some of the oil as the core was brought to the surface, or if the core was not well preserved, the pay interval may not fluoresce uniformly.²

It is difficult to assess fluorescence using the naked eye; however, digital color photography records numerical input, which some operators use for subsequent computer analysis.³ Each photograph is made up of pixels, and each pixel may

be assigned one of more than 16 million shades. Geoscientists filter or manipulate these colors to highlight important features. Statistical analysis of color data can help geologists differentiate between lithologies or establish porosity or permeability cutoffs. The computer can count how many pixels fall within a specified color range to determine net sand or net fluorescence in thinly laminated zones.

Although core facilities typically accommodate a wide range of samples, core plugs are most frequently used for routine core analysis. Plugs provide

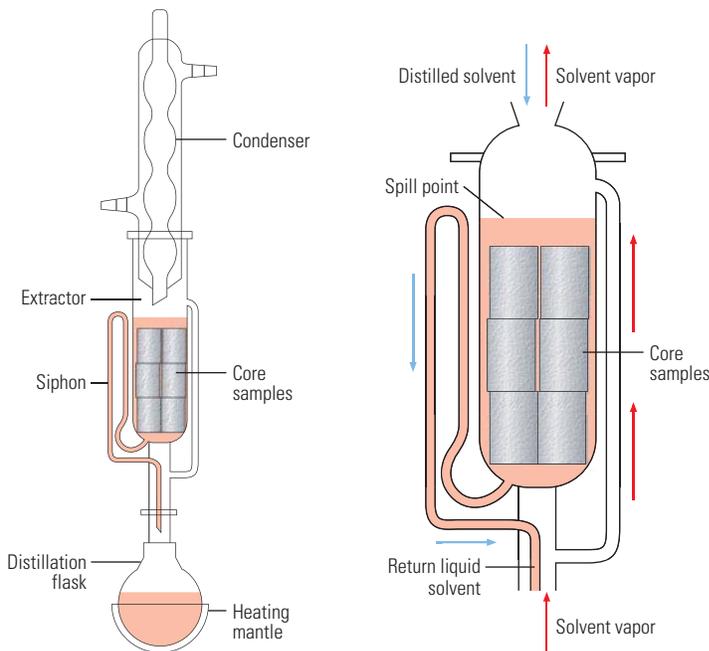
Solvent	Boiling Point	Solubility
Methylene chloride	40.1°C [104.25°F]	Oil and limited water
Hexane	49.7°C to 68.7°C [121.5°F to 155.7°F]	Oil
Chloroform/methanol azeotrope	53.8°C [128.8°F]	Oil, water and salt
Acetone	56.5°C [133.7°F]	Oil, water and salt
Methanol	64.7°C [148.5°F]	Water and salt
Tetrahydrofuran	65.0°C [149.0°F]	Oil, water and salt
Cyclohexane	81.4°C [178.5°F]	Oil
Ethylene chloride	83.5°C [182.3°F]	Oil and limited water
Toluene	110.6°C [231.1°F]	Oil
Tetrachloroethylene	121.0°C [249.8°F]	Oil
Xylene	138.0°C to 144.4°C [280.4°F to 291.9°F]	Oil
Naphtha	160.0°C [320.0°F]	Oil

^ Common core-cleaning solvents, ordered by boiling point temperature. The choice of solvent typically depends on wettability interactions between the crude oil and the minerals contained within the rock. Complete extraction of some oils may require mixtures or series of solvents. The red line represents the boiling point of water. (Table adapted from API, reference 6.)

a reliable characterization of the core when the pore system is relatively homogeneous.⁴

The core analyst, sometimes working in concert with the operator's geologist, drills sample plugs from a full diameter core. Most laboratories use a mill or a drill press with a diamond bit to drill the core plugs. The analyst cuts the plug to a

standard length then applies a precision finish using an end face grinder. The result is a right cylinder, typically 38 mm [1.5 in.] diameter by 64 mm [2.5 in.] long, with a flat face at each end. By creating plugs of standard shape and size, the analyst obtains samples with the same cross-sectional area and length; thus, each plug has essentially



^ Soxhlet distillation extractor. Solvent in the distillation flask (left) is gently heated until it vaporizes. The solvent vapors rise from the flask and cool when they reach the condenser. The cooled liquid solvent drips onto the core to permeate the sample. The solvent condensate carries away the hydrocarbons and brine from the sample. When distilled solvent in the extractor reaches its spill point, the used solvent siphons back into the flask to be redistilled (right). This process is repeated continuously and can be sustained as long as needed. The hydrocarbons from the core are retained and concentrated in the distillation, or boiling, flask. Some Soxhlet devices can accommodate multiple core plugs.

the same bulk volume. A standard size plug also reduces the potential for measurement errors stemming from irregularly shaped samples.

Core Cleaning and Fluid Extraction

In addition to rock matrix, core samples contain formation fluids. If the core is taken from a productive zone, these formation fluids will typically contain a mixture of hydrocarbons and saltwater, or brine. At the laboratory, these fluids, which would otherwise interfere with routine core analysis measurements of porosity and permeability, must be completely removed from the pore spaces of the rock.

Core cleaning and fluid extraction are combined in a delicate process, which must be thorough enough to remove heavy fractions of crude oil yet gentle enough to prevent damage to the mineral constituents of the rock. This process must avoid creation of additional pore space resulting from dehydration of clays and hydrous minerals, such as gypsum, or from erosion caused by high flow rates as solvent passes through the sample.⁵ Several techniques have been developed for removing residual formation fluids; the most widely used involve distillation extraction or continuous solvent extraction.

Unslabbed cores, plugs and SWCs are carefully cleaned using a specialized closed-loop system that employs either a Soxhlet cleaning treatment or a Dean-Stark fluid extraction process. In the Soxhlet process, the sample is allowed to soak in the solvent; in the Dean-Stark method, solvent vapors and liquids flow through the sample. Both techniques rely on heat to drive the water from the core sample and on solvent to extract any hydrocarbons (above left).

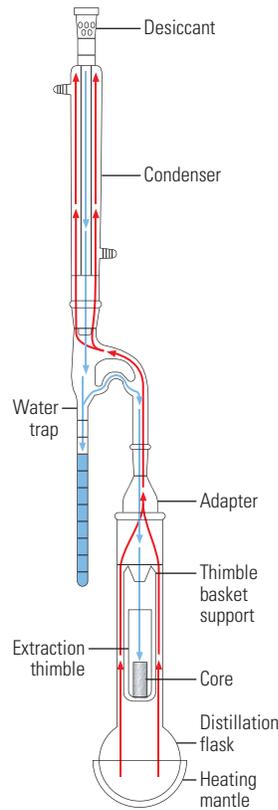
Soxhlet extraction uses a distillation process to clean the core. The Soxhlet apparatus consists of a heating mantle with a thermostatic controller, boiling flask, extractor and condenser (left). The solvent is gently boiled, and the distilled solvent collects in the extractor, in which one or more core samples soak. The heated solvent is continually distilled, condensed and refluxed. The cleanliness of the sample is determined from the color of the solvent that siphons periodically from the extractor; the process is repeated until the extract remains clear after an extended soak cycle. This method uses one or more solvents to dissolve and extract oil and brines from the core sample.

After repeated cycles, the extract should become clear as no more oil is carried out of the rock. However, the fact that one solvent is clear may not necessarily mean that the oil has been completely removed from the sample.⁶ Sequentially stronger solvents may be required to clean the sample.

Another distillation method, Dean-Stark extraction, is an industry standard method for determining fluid saturation (right). The core analyst first weighs the sample on an analytical balance before placing it into a thimble in the Dean-Stark apparatus above its heating flask. The flask is heated to raise the solvent temperature to its boiling point, and the sample becomes enveloped in solvent vapors as they rise from the flask. Water in the sample is vaporized by the solvent and rises with the solvent vapors to the condenser. There, the vaporized water and solvent cool and condense before falling into a calibrated receiving tube.

The water, denser than solvent, settles to the bottom of the receiving tube. When the solvent condensate overflows the tube, it drips down onto the sample. The condensate mixes with oil in the rock, and this mixture drips back into the flask below, where the solvent is again heated and the vaporization-condensation cycle continues. Once the volume of water in the receiving tube reaches a constant value, with no more water produced from the sample, the Dean-Stark distillation is complete. Because the sample may not be completely cleaned of oil and salts, a Soxhlet cleaning often follows the Dean-Stark method before the sample is placed in the oven to dry.

The core analyst weighs the sample after Dean-Stark extraction and Soxhlet cleaning and periodically during drying (right).⁷ The difference between sample weights before and after cleaning is attributed to the weight of the extracted fluids. The calibrated receiving tube measures the extracted water volume, which is converted to weight by using the density of distilled water. The remaining weight difference is a result of any oil that has been extracted. Typically, an oil density value is assumed for determining the oil volume based on weight.



^ Dean-Stark apparatus. A core analyst inserts a core plug into the sample chamber (photograph). The typical setup (left) consists of an electric heating element, or heating mantle, a boiling flask with extractor chamber, a sample thimble or support screen, a water trap or calibrated receiving tube, and a condenser. The Dean-Stark method results in a quantitative measure of water volume extracted from a core, and therefore each sample is cleaned individually in a separate apparatus.

4. Almon WR: "Overview of Routine Core Analysis," in Morton-Thompson D and Woods AM (eds): *Development Geology Reference Manual, Part 5—Laboratory Methods*. Tulsa: The American Association of Petroleum Geologists, AAPG Methods in Exploration Series, no. 10 (October 1, 1993): 201–203.
5. Macini P and Mesini E: "Petrophysics and Reservoir Characteristics," in Macini P and Mesini E (eds): *Petroleum Engineering—Upstream, Encyclopaedia of Life Support Systems (EOLSS) 2008*, developed under the auspices of the United Nations Educational, Scientific and Cultural Organization, EOLSS Publishers, Oxford, England, <http://www.eolss.net> (accessed July 16, 2013).
6. American Petroleum Institute (API): *Recommended Practices for Core Analysis*. Washington, DC: API Exploration and Production Department, Recommended Practice 40, Second Edition, February 1998.
7. The core is dried in an oven until its weight is constant over a specified time interval, which implies that all the water has evaporated. Normally, a convection or vacuum oven is used to dry the samples. However, if the cores contain gypsum or hydratable clays, then they are dried in an oven equipped with a water vapor injection system to regulate relative humidity.



^ Weighing core plugs. Precision weighing of every sample at each stage in the cleaning and extraction process is required because small differences in weight affect grain density calculations and subsequent determination of other important reservoir parameters such as fluid saturation.

Later, analysts measure the pore volume of the core sample; the difference between the pore volume and the sum of the water and oil volumes is the gas volume. These fluid volumes are converted to saturations by dividing by the pore volume.

Laboratories sometimes use other cleaning and extraction techniques to accommodate different types of rock. Analysts developed a technique for cores containing very fine clays with delicate mineral structures. The cores are cleaned with a series of mutually miscible solvents, injected in sequence such that each solvent displaces a specific pore fluid and each solvent in the sequence is displaced by the next. During flow-through cleaning, solvent may be either injected continuously or periodically halted to allow it to permeate the core.

For quick processing of cores, laboratory workers may use a rapid extractor that injects heated solvent into the sample. Multiple cores can be analyzed in a single operation; each sample is placed into a separate pressure vessel, then the rapid extractor heats and pumps solvent into the samples at high pressure. The displaced fluids are collected separately for each sample.

Key Measurements

Porosity and permeability are essential measurements for understanding how a reservoir will produce. Porosity, a measure of reservoir storage capacity, can be determined by measuring grain volume, pore volume and bulk volume (below). Only two of the three volumes are required to determine porosity, and pore volume is measured under simulated overburden stress conditions.

$$\phi = V_p / V_b,$$

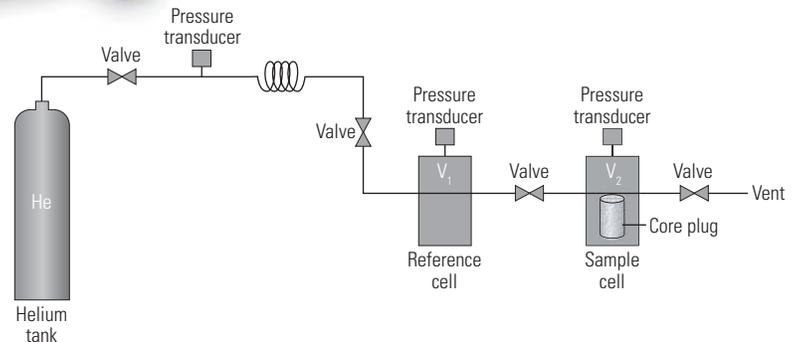
$$\phi = (V_b - V_g) / V_b,$$

$$\phi = V_p / (V_p + V_g),$$

where

- ϕ = porosity
- V_p = pore volume
- V_b = bulk volume
- V_g = grain volume

^ Porosity relationships. Porosity is defined as the ratio of pore volume to bulk volume. Because bulk volume is the sum of grain volume and pore volume, measuring any two of these volumes allows for calculation of the third, with subsequent calculation of porosity.



^ Boyle's law porosimeter. A porosimeter (top) measures the pressure difference between a reference chamber and a sample chamber to determine pore and grain volumes. The basic system diagram (bottom) shows the inner workings of a porosimeter, with its reference chamber of fixed, known internal volume and a sample chamber. The device also has valves to admit a gas under pressure to each chamber, transducers to measure pressure and requisite plumbing to permit communication between a pressurized gas container and the two chambers. Calibration, operation of valves and calculation of results are completely automated. (Photograph courtesy of Coretest Systems, Inc.)

Over the years, scientists have developed various methods for measuring these core volumes; most are based on physical measurements of weight, length, volume or pressure. Some of these measurements are obtained directly from the sample; others rely on the displacement of fluids.

Direct measurements may be taken to determine bulk volume. The core analyst may simply use a digital caliper or micrometer to measure the core plug length and diameter. A minimum of five measurements is recommended. The cross-sectional area of the core plug is calculated from the average diameter, then multiplied by the average length to yield bulk volume.⁸ In some laboratories, digitally calipered core measurement data are automatically logged into a computer, which calculates the geometric bulk volume, shape factor, effective flow area and caliper bulk factor.

Other techniques are based on Archimedes' principle of fluid displacement: A solid submerged completely in fluid displaces an amount of fluid equal to its volume. Displacement can be measured volumetrically or gravimetrically.

The volumetric approach for finding bulk volume uses a small amount of mercury in a porosimeter.⁹ First, the empty sample chamber of the porosimeter is filled with mercury to determine its volume. The mercury is then drained from the chamber and the core plug is inserted. The cham-

ber is again filled with mercury. The volume of mercury that filled the empty chamber minus the volume needed to fill the chamber while it held the sample equals the sample's bulk volume.

The gravimetric approach uses a beaker of mercury placed on a laboratory balance. After the beaker and mercury are weighed, a cleaned, dried core plug of known weight is submerged in the mercury. The weight gain from the sample submersion, divided by the density of mercury, gives the bulk volume. Today, many laboratories prefer not to use mercury and instead apply Archimedes' principle using other fluids such as brine, refined oil or toluene.¹⁰

After determining bulk volume, the analyst measures the grain and pore volume of the samples. The most rapid and widely used device for measuring grain volume and pore volume—and hence, determining porosity—is the automated porosimeter (above). This device employs Boyle's law to calculate porosity based on the pressure decrease measured when a known amount of fluid is vented into an expansion chamber containing a core. In this case, the fluid is helium gas.¹¹

To measure pore volume, the analyst places a cleaned and dried core sample in a core holder fitted with an elastomer sleeve. When air pressure is applied to the outside of the sleeve, it conforms to the shape of the core. The core holder is

$$P_i V_i = P_f (V_i + V_l + V_p),$$

where

P_i = initial pressure

P_f = final pressure in the system

V_i = initial volume in reference chamber

V_l = volume of connecting lines

V_p = pore volume of sample

^ Pore volume calculation. Following Boyle's law, the pore volume can be calculated using the difference between initial and final pressures in the porosimeter.

used in place of the porosimeter sample chamber. The reference chamber is initially isolated from the core in the holder and filled with helium to a specified pressure. The valve to the sample chamber is then opened to permit the helium pressure to equilibrate between the reference chamber and the pore volume of the confined sample. Porosity is calculated using the bulk and pore volume measurements (above). The process for measuring grain volume is similar, except that the sample is not confined, but is placed, with no sleeve, directly into the sample chamber.

Permeability, the measure of a rock's capability to transmit fluids, is another key reservoir characteristic. In the laboratory, analysts determine permeability by flowing a fluid of known viscosity at a set rate through a core of known length and diameter then measuring the resulting pressure drop across the core. For routine core analysis, the fluid may be air, but is more often nitrogen or helium, depending on the type

8. API, reference 6.

9. Mercury is used because it is a nearly perfect nonwetting fluid and does not enter the rock pores under normal pressure.

10. API, reference 6.

11. Helium is used because it is an inert gas that does not readily adsorb onto mineral surfaces of the core and tends to exhibit ideal gas behavior at moderate pressures and temperatures. Furthermore, the small size of the helium atom enables it to rapidly enter the micropore system of the core, penetrating very small pores approaching 0.2 nm.

For more on porosity analysis: Cone MP and Kersey DG: "Porosity," in Morton-Thompson D and Woods AM (eds): *Development Geology Reference Manual, Part 5—Laboratory Methods*. Tulsa: The American Association of Petroleum Geologists, AAPG Methods in Exploration Series, no. 10 (October 1, 1993): 204–209.

12. API, reference 6.

13. Klinkenberg LJ: "The Permeability of Porous Media to Liquids and Gases," *Drilling and Production Practice*, (1941): 200–213.

Rushing JA, Newsham KE, Lasswell PM, Cox JC and Blasingame TA: "Klinkenberg-Corrected Permeability Measurements in Tight Gas Sands: Steady-State Versus Unsteady-State Techniques," paper SPE 89867, presented at the SPE Annual Technical Conference and Exhibition, Houston, September 26–29, 2004.

of permeameter used. The analyst loads a clean, dry core into a specially designed core holder, where it is enclosed in a gas-tight elastomer sleeve (below). The permeameter forces pressurized gas through the inlet port and into the core. The pressure differential and flow rate are metered at the outlet port. This configuration is used in a steady-state gas permeameter.

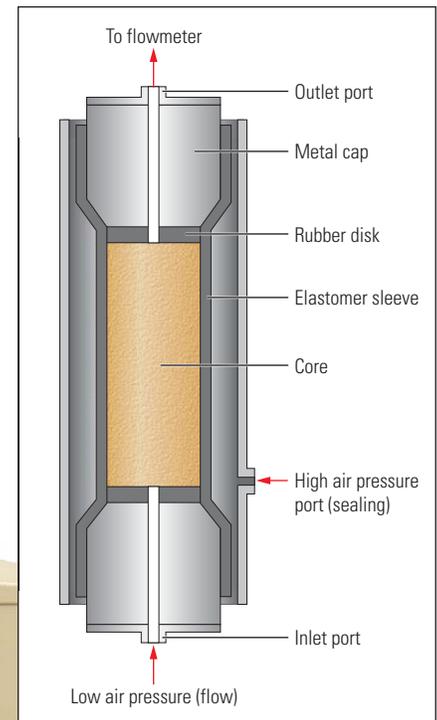
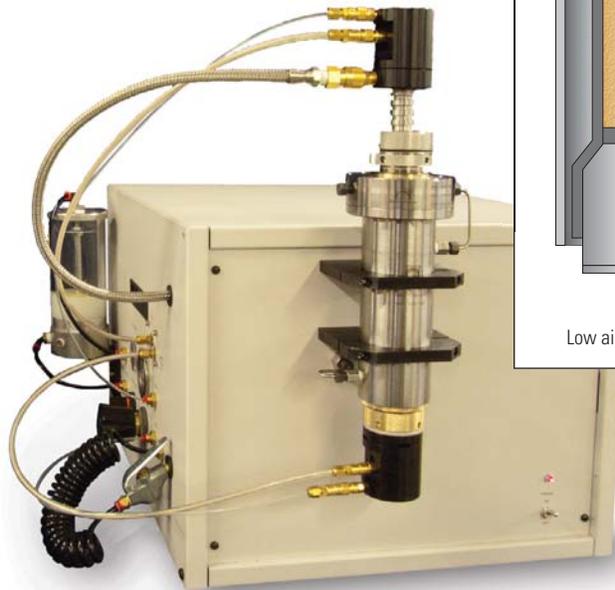
In an alternative method for determining permeability, analysts charge a chamber to a high gas pressure and then open a valve, allowing the gas to pass through the core plug as the pressure declines. If the laboratory uses this unsteady-state, or pressure-transient permeameter, analysts can use the time rate of change of pressure and effluent flow rate to solve for the plug permeability.

Analysts apply corrections to compensate for the differences between laboratory and down-hole conditions.¹² They account for stress differences by applying confining stress to one or more representative plug samples; some permeameters are capable of imposing confining pressures to 70 MPa [10,000 psi]. Often, analysts use several confining stresses to determine the stress effect on permeability then apply a correction

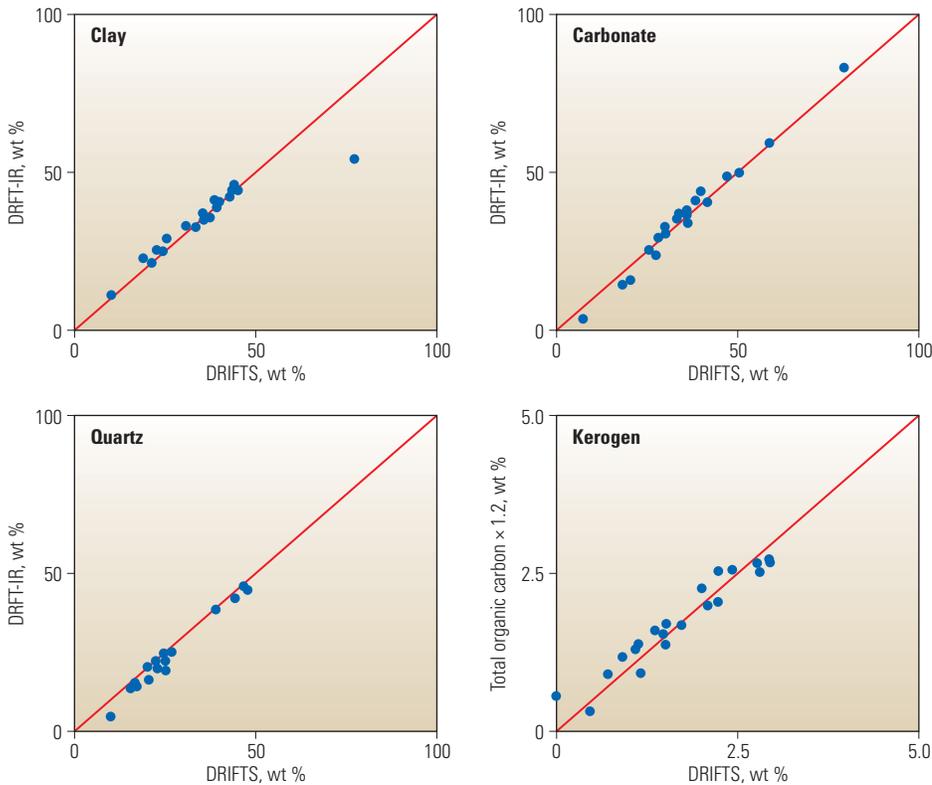
factor for the reservoir confining stress to the other routine permeability measurements.

Gas flow in pores differs from liquid flow because the flow boundary condition at the pore walls is different for gases and liquids. Liquids experience greater flow resistance, or drag, at the pore wall than gas does. This gas slip effect can be corrected by increasing, in steps, the mean gas pressure in the plug, which increases the drag at the pore wall. The Klinkenberg correction is an extrapolation of these measurements to infinite gas pressure, at which point gas is assumed to behave like a liquid.¹³

Analysts apply an additional correction for high gas flow rates through tortuous flow paths. The Forchheimer correction accounts for effects produced when gas accelerates as it passes through small pore throats and decelerates upon entering the pores. In many automated unsteady-state permeameters, both the Klinkenberg and Forchheimer corrections are automatically solved during analysis.



^ Hassler chamber for measuring permeability to gas. A core sample is placed in an elastomer sleeve. The caps at either end of the device are fitted with axial ports to admit gas. The permeameter (photograph) forces gas through the inlet port at the bottom, and the gas passes through the core before exiting to a flowmeter. Permeability is calculated using the Darcy equation. (Photograph courtesy of Coretest Systems, Inc.)



▲ Confirmation of DRIFTS measurements. Results from the DRIFTS measurement in the vertical evaluation well compare favorably with companion DRFT-IR mineralogy for clay, carbonate and quartz content. The kerogen content from DRIFTS was compared with a LECO TOC measurement. DRIFTS measures wt % of the kerogen, which includes other elements than carbon; therefore, the industry uses a factor of 1.2 to correlate between these TOC and kerogen measurements. The above plots show good agreement between DRIFTS and the other measurements.

Upon completion of its analyses, the laboratory transmits a report, along with digital copies of photographs and scanning data, to the client. Depending on client instructions, the core may be kept in storage, returned to the client, or archived at a core library for future reference.

Petrographic Measurements

Routine core analysis helps operators evaluate reservoir lithology, bedding features, residual fluids, porosity and permeability, but these provide only a portion of the information that can be extracted from a core. Complementary petrographic tests furnish additional analytical results and visual records of the core.

Scanning electron microscopy allows inspection of core surface topographies with magnifications capable of resolving features at the nanometer scale. A scanning electron microscope scans the surface of a sample with a finely focused electron beam to produce an image based on beam-specimen interactions.

Electron detectors receive data on specimen surface topography while backscatter detectors resolve compositional variations across the sample surface.

Analysts use a color cathodoluminescence detector to examine variations in mineral composition, including phase and trace element distribution. This detector permits visualization of chemical overprinting and overgrowths, growth zonation and internal healed fractures. These images provide insight into processes involving the growth of mineral crystals as well as their replacement, deformation and provenance. Petrologic applications include investigations of cementation and diagenesis of sedimentary rocks, provenance of clastic rock materials and examination of the internal structures within fossils.

Diffuse reflectance infrared Fourier transform spectroscopy (DRIFTS) provides a fit-for-purpose technique for measuring mineralogy and organic content—data that are proving instrumental in supporting completion designs in mud-

stone reservoirs. Scientists can analyze core, cuttings or outcrop samples. DRIFTS analysis is fast; a 50-second scan determines mineralogy and organic content. A sample preparation procedure that is proprietary to Schlumberger enables it to be used as a quantitative measure of rock constituents. The process requires a small sample of only 5 g [0.18 ozm] for analysis.

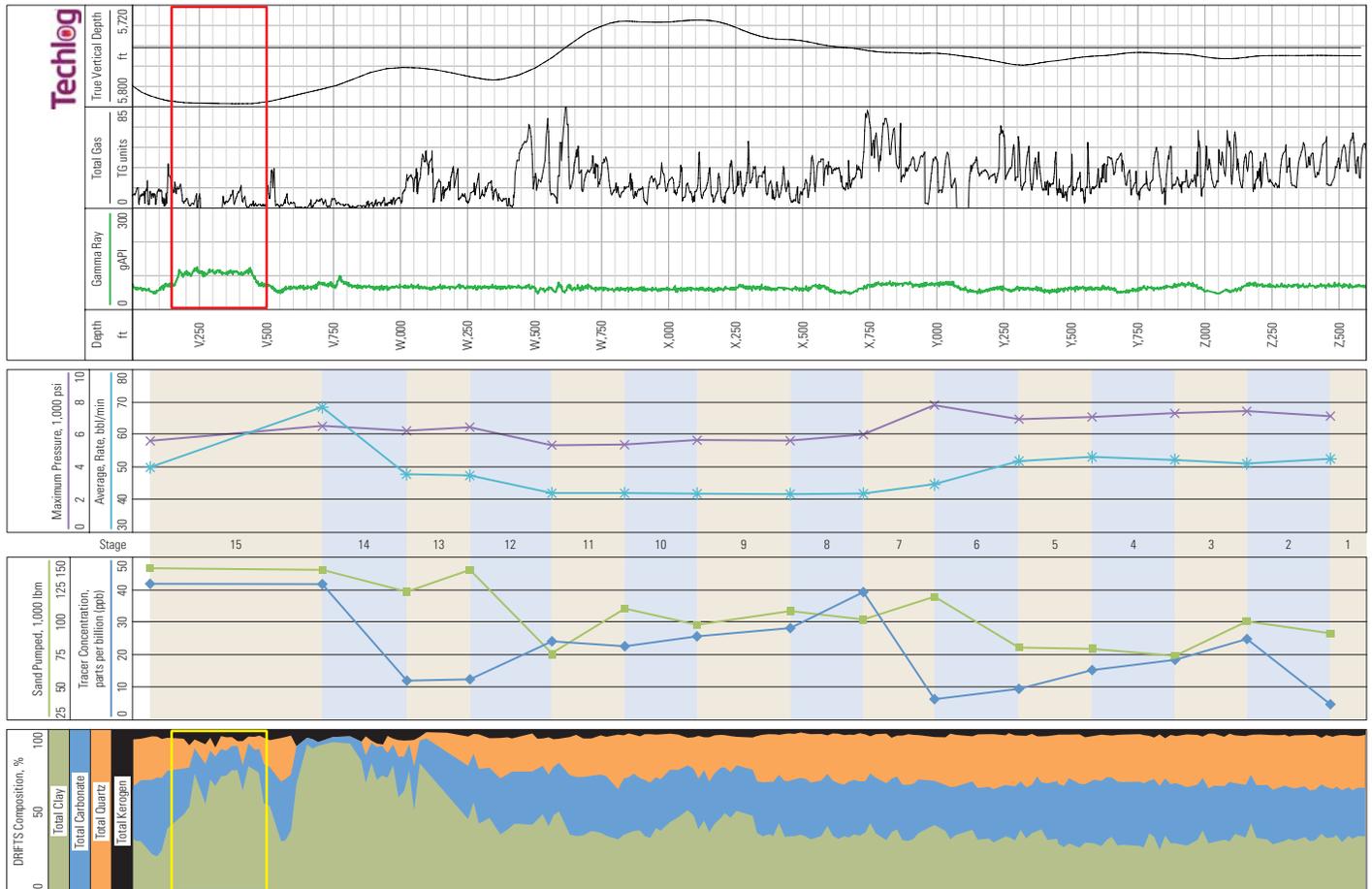
The device scans the sample with infrared light at multiple wavelengths. The light scatters as it passes through the rock. The reflected infrared energy is analyzed based on regression analysis of the frequency and amplitude of the spectra to determine the lithology, mineralogy and organic content of each sample.

To obtain an initial calibration of mineralogy and kerogen measurements, analysts run dual range Fourier transform infrared (DRFT-IR) spectroscopy and X-ray fluorescence (XRF) on representative samples to verify mineralogy, and they run a LECO total organic carbon (TOC) scan to verify organic matter content and kerogen amount. After the full study of DRFT-IR, XRF and TOC is complete, DRIFTS data can be acquired on a rapid basis to give operators timely information for completion decisions.

An operator in the western US performed DRIFTS analyses on Mancos Shale wells to evaluate their utility for identification of mineralogy and kerogen content in unconventional plays. The first study focused on a vertical well that was cored and logged. This well provided an extensive database for evaluating the Mancos Shale.

The laboratory used crushed samples from cores to determine mineralogy and organic content. In addition to DRIFTS data, the evaluation included mineralogy from DRFT-IR, XRF and TOC measurements. These traditional analytical methods utilized material from the same crushed samples that were subjected to DRIFTS analysis. Results from these evaluations showed good agreement between the DRIFTS results and the other three more accurate analytical methods (above left). The results gave the operator confidence to apply the DRIFTS method to other wells drilled in the Mancos formation.

The second well in this study was a horizontal production well. Near the heel of the well, high gamma ray measurements and low mud log gas readings suggested that the well might be out of the primary target zone. The gamma ray response decreased as the well moved upward in the stratigraphic section, indicating better reservoir quality in the targeted portion of the well; this was consistent with mud log gas readings toward the toe of the well.



^ Response in a bentonite zone. The gamma ray log (Track 3 from top) reads high from V,100 to V,400 ft measured depth, interpreted as a bentonite zone (red box). The well trajectory (Track 1) was changed to drill upward through this zone. The high gamma ray signature, combined with low mud gas readings (Track 2), is a typical indicator of poor reservoir quality. All zones of this horizontal well were stimulated. In the bentonite zone, the injection rate required to fracture was higher at the same pressure (Track 4). A tracer survey (Track 5) shows the presence of a chemical tracer throughout the 15-stage interval, indicating that the proppant was successfully placed at each stage. The DRIFTS analysis (Track 6) indicates that kerogen is present throughout this zone, which gave petrophysicists confidence that the bentonite zone (yellow box) was a thin zone in a productive Mancos formation, despite high gamma ray and low mud gas readings.

In the toe of the wellbore, the DRIFTS data recorded values above the operator's minimum cutoff for kerogen content along with acceptable values of clay, carbonate and quartz, in agreement with gamma ray and mud gas data (above). From the heel of the well, other data showed unacceptably high clay content, supporting the earlier gamma ray interpretation that the well had drilled out of zone. However, the DRIFTS data showed anomalously high kaolinite values at the heel of the well, typical of thin bentonite layers known to exist in the Mancos Shale. The heel also exhibited higher kerogen content (5.6% compared with a range from 3.1% to 4.3% in the toe of the well). These observations, not available through MWD logs obtained in this well, gave the operator confidence that the bentonite zone was a thin anomaly, not representative of the Mancos formation surrounding it.

Postfracturing data indicate that the well was successfully stimulated with adequate proppant placement, although higher injection rates were needed to successfully break down the clay-rich bentonite zone. The operator is incorporating these data in completion optimization studies for future wells.

Operators combine other data with these important ground truth measurements in their formation evaluation programs. Core analysis, in its many forms, will continue to inform operator decisions to drill ahead, abandon or complete their wells.

In some cases, routine analysis and petrology provide an operator with all the core information needed. More commonly, additional analyses are obtained from this valuable asset. These include evaluations of multiphase saturation and flow properties, such as capillary pressure and relative

permeability; log-tuning measurements, such as electrical properties for determining porosity and saturation from logs; flow assurance studies; geo-mechanical measurements or enhanced oil recovery evaluations. These measurements add tremendous value to reservoir evaluation, and they all begin with routine core analysis. —MV