Pressure measurement is essential to optimized hydrocarbon recovery. Now, accurate formation pressures can be determined at almost any time in a well’s life cycle. Whether while drilling, when the well is at total depth, or years after initial production, accurate, cost-effective pressure data can be acquired to help reduce risk and improve recovery.

Many everyday pressure effects go unnoticed. We seldom consider why water flows from a tap or how an airplane flies. And certainly, while fueling the family automobile, the nature of geopressures that drive hydrocarbons to the surface is far from our minds. Our world relies on pressure in many ways, not the least of which is the production of oil and gas.

The story of geopressure is rooted in the Earth’s beginning. As the molten outer core of the Earth cooled, plate-tectonic movements driven by convection within the Earth generated stresses in the crust. Movement, warping and buckling of these stressed crustal plates caused mountains and basins to form. Volcanic eruptions associated with plate-tectonic forces spewed material from within the Earth, forming the atmosphere and oceans.

As plate-tectonic activity continued to influence subsurface pressure conditions, weather patterns formed. Cycles of oceanic evaporation, atmospheric saturation, condensation and inland precipitation fueled rivers that run to the oceans, carrying with them large amounts of eroded rock and terrigenous and marine organic material. As the transport velocity slowed, these materials settled in depositional basins (below). Later, during continued burial and compaction, these

^ The hydrologic cycle. Evaporation of water from the ocean forms clouds. These clouds drift over the land and produce rain that flows along rivers back to the ocean, carrying with it rock and organic debris that accumulates in basins. The cycle repeats, depositing massive layers of material.
materials were transformed by heat, pressure and organic activity into the many hydrocarbon compounds we know as petroleum.

Thus begins the story of geopressure, hydrocarbons and production. In this article, we first review the development of geopressed systems, and then discuss the effects of formation pressure on drilling, evaluation, production and recovery of hydrocarbons. Case histories from the Gulf of Mexico, Mexico and the North Sea show how drillers, engineers and geoscientists are using advanced techniques to predict, measure and manage pressure, allowing wells to be drilled more safely, boreholes to be placed more accurately, and reservoir contents to be evaluated and managed for maximum oil and gas recovery.

Development of Geopressed Systems

The Earth’s outer crust hosts a complex system of stresses and geopressures that constantly seek equilibrium. Although the subsurface comprises many geologic features in different pressure and stress regimes, one of the most commonly studied subsurface pressure distributions occurs in relatively shallow sediments, laid down in deltaic depositional environments. Rivers wash large amounts of sand, silt and clay into offshore basins where they accumulate, are lithified over millions of years and form primarily sandstone, siltstone and shale.

Initially, the sediments deposited at the mouths of rivers are unconsolidated and uncompacted, with relatively high porosity and permeability that allow remnant seawater, or connate water, in the pores to remain in full hydraulic communication with the ocean above. With time and compaction as more sediment is deposited, water is squeezed out of pore spaces and grain-to-grain contact supports more and more of the depositional load. Provided there is a conduit for the water to escape, pressure equilibrium is maintained in the pore spaces.

Once formed, oil and gas migrate upward to zones of lower pressure, possibly reaching the surface to form seeps if there is no mechanical blockage along the way. Geological and archeological evidence shows that hydrocarbon seeps have occurred naturally in various parts of the world for thousands of years. In some cases, subsurface pressures drive large volumes of hydrocarbons to the surface. Along the California coast near Goleta Point, USA, commercial volumes of natural gas continue to escape from natural fractures in the Earth’s crust. Here engineers designed a unique underwater gas-recovery system, capturing more than 4,000 million ft³ [113 million m³] of natural gas since 1982. This is enough natural gas to supply the annual needs of more than 25,000 typical California residential consumers.

Seeps generally occur where erosion exposes hydrocarbon-bearing rocks at the Earth’s surface, or where a fault or fracture allows pressure-driven hydrocarbons to migrate to the surface. Historical records indicate that surface seepage led to the discovery of many petroleum deposits. Today, aerial and satellite imagery helps geologists detect natural oil and gas seeps migrating from great ocean depths, offering the promise of yet undiscovered hydrocarbon reserves.

Seeps can be identified offshore Angola, West Africa. About 75% of the world’s petroliferous basins contain surface seeps. Knowing where oil and gas seeps are emerging is helpful in locating the sources of subsurface oil and gas accumulations. Scientists use satellite imagery to help identify potential hydrocarbon reservoirs. In this image, free-air gravity values derived from European Remote-Sensing Satellite (ERS) data identify areas of high gravity resulting from sediment emitted from the Congo River, known as the Congo Fan. The data are also used to help identify areas of hydrocarbon seepage shown as red-outlined contours. The subsea seep source is typically located using sonar or shallow seismic reflection. The hydrocarbons can then be sampled, helping to identify oil type and field maturity and to correlate with other subsea seeps. (Image courtesy of NPA Group; Archive block outlines courtesy of IHS Energy.)
changes caused by plate-tectonic activity or the plastic deformation of salts or shales (above). Many hydrocarbon traps involve combinations of structural and stratigraphic features, but once trapped beneath a seal, reservoir fluids have no hydraulic communication with the surface. Given time and the right circumstances, pressure increases in the rock pore space (see “Causes of Abnormal Pressure,” page 26).

Early Oil and the Uncertainty of Pressure

Sometime before 200 BCE, the Chinese relied on geopressure to help produce the first gas wells. Other records indicate that as early as 1594, near Baku, Azerbaijan, shallow pits or wells were dug by hand to depths of 35 m [115 ft], making this area the first actual oil field.

In the USA, the history of drilling prior to the 19th Century is unclear, although seep-oil use is noted in numerous early historical accounts. In 1821, drillers completed the first well in the USA designed specifically to produce natural gas. This well, in Fredonia, New York, USA, reached a depth of 27 ft [8.2 m] and produced enough gas, driven by natural pressure, to light dozens of burners at a nearby inn. Then, Edwin L. Drake drilled an exploratory well in 1859 near Titusville, Pennsylvania, USA, to locate the source of an oil seep. At a depth of 69.5 ft [21 m], drillers pulled their tools from the well. Within 24 hours, geopressure effects forced oil up the borehole. Fortunately for Drake, oil seeps in the area precluded abnormal pressure buildup. Using a manual pump, drillers produced about 25 bbl/d [3.9 m3/d] of oil. Although production soon dropped to around 10 bbl/d [1.5 m3/d], the well is said to have continued producing for a year or more.

By the early 1900s, drillers, geoscientists and engineers recognized the importance of geopressure in oil and gas production. The Spindletop discovery, which blew out during drilling near a salt dome at 1,020 ft [311 m], produced around 800,000 bbl [127,120 m3] of oil in eight days and provided scientists with insights into salt dome-related abnormal geopressure effects.

As drilling activity increased, exploration reached into new and uncharted territories. Remembering the uncontrolled oil gushers of the past, drillers were constantly on the lookout for abnormal geopressures. Engineers and scientists began to seek new ways to predict abnormal pressures during the search for oil.

At around the same time that Drake drilled his first well, seismic instruments were being developed and used to record and measure Earth movements during earthquakes. Researchers developed the technologies that form the basis of reflection seismology. In reflection seismology, subsurface formations are mapped by measuring the time it takes for acoustic pulses transmitted into the Earth to return to the surface after being reflected by geological formations with varying physical properties. Over time, seismic technology moved into the oil field, providing geophysicists, geologists and drilling engineers with the tools to evaluate reservoirs and pressure regimes long before drilling a well.

Although early geopressure estimations from seismic image analysis were crude, drillers needed predrilling pressure estimates for mud-weight selection, casing design and well-cost estimation, among other uses. Engineers found early pressure estimates too uncertain, especially in complex oil and gas reservoirs. To more easily understand and visualize the geopressure environment, geoscientists now use sophisticated seismic data acquisition and processing techniques, mechanical earth models and pore-pressure cubes to study, evaluate and visualize pressure environments within a given basin or area.

Engineers use reflection tomography that yields higher spatial resolution than conventional seismic techniques to accurately predict pore pressure from seismic data. This high resolution also helps differentiate variations in pore pressure from variations in lithology and fluid content.

(continued on page 28)
Causes of Abnormal Pressure

Normally pressured formations generally have pore pressure that equals the hydrostatic pressure of the pore water. In sedimentary basins, pore water usually has a density of 8.95 lbm/galUS [1,073 kg/m³], which establishes a normal pressure gradient of 0.465 psi/ft [10.5 kPa/m]. Significant deviation from this normal hydrostatic pressure is referred to as abnormal pressure.

Abnormal geopressures, above or below the normal gradient, are found in many hydrocarbon-producing reservoirs. While the origin of these pressures is not understood completely, abnormal pressure development is usually attributed to the effects of compaction, diagenetic activity, differential density and fluid migration. Abnormal pressure involves both physical and chemical actions within the Earth. Pressures above or below the normal gradient may be detrimental to the drilling process.

Subnormal pressures, or those below the normal gradient, can cause lost-circulation problems in wells drilled with liquid drilling mud. Subnormal pressure conditions frequently occur when the surface elevation of a well is much higher than the subsurface water table or sea level. This is seen when drilling in hilly or mountainous locations, but it may also occur in arid regions where the water table may be more than 1,000 ft [305 m] deep.

Abnormally low pressures are also frequently found in depleted reservoirs. These are reservoirs whose original pressure has been reduced by production or leakage. Depletion is not unusual in mature reservoirs from which significant volumes of oil and gas have been produced without waterflooding or pressure maintenance.

By contrast, abnormally high pressures are typical in most oil-producing regions. Abnormal overpressures always involve a particular zone becoming sealed or isolated. The amount of overpressure depends on the structure, the depositional environment and the processes and rate of deposition.

Pressure isolation by fault displacement. In zones of faulting, pressure-bearing zones (brown) can be displaced along a fault plane. If adequately sealed, the displaced zone maintains its abnormal pressure. Although the top of an abnormally pressured zone may be defined in a given area or structure, faulting can cause significant changes in formation depth only a short distance away. For the driller, this not only is confusing but also causes an increased drilling risk.


One of the most common mechanisms generating abnormally high pressures is trapping of pore water during deposition. If a seal forms before pore water is displaced, grain-to-grain contact between solids is not established. Over time and with increases in compaction due to overburden pressure, the water in the pore space becomes compressed, causing abnormally high pore pressure.

Another cause of abnormally high geopressure is geologic uplifting and displacement of a formation, which physically relocates a higher pressured formation from one depth to another (previous page). When a previously normal pressure zone at great depth is displaced by tectonic activity to a shallower depth with the seals remaining intact, the resulting pressure will be abnormally high.

Undercompaction during deposition is another mechanism for generating high pore pressure. In the Gulf of Mexico and other depositional basins, compaction disequilibrium is believed to be the most important cause of overpressure. For sediment to compact, pore water must be expelled. However, if sedimentation is rapid compared to the time required for fluid to be expelled from the pore space, or if seals that prevent dewatering and compaction form during burial, the pore fluid becomes overpressured and supports part of the overburden load.

Artesian systems are a unique source of abnormally high pressures. In these systems, the surface elevation of the well is below sea level or below the water table. This commonly occurs when drilling in a valley or basin surrounded by hills or mountains—locations where a connected water table is charged by water from higher locations.

Overpressures can also occur in shallow sands if higher-pressured fluids migrate from lower formations as the result of faulting or through a seal in a network of microfractures (below right). In addition, man-made actions can charge upper sands. Poorly cemented casings, lost circulation, hydraulic fracturing and underground blowouts can cause otherwise normally pressured zones to become abnormally pressured.

Another cause of overpressure is chemical activity. If massive deposition of organic material becomes sealed with time and exposed to higher temperatures, this organic matter generates methane and other hydrocarbons that charge the formation. Increasing depth, temperature and pressure may cause gypsum to convert to anhydrite, releasing water that may charge a formation. Conversely, anhydrite that is exposed to water may form gypsum, resulting in as much as a 40% increase in volume, thereby increasing zonal pressures. Pore pressure may also be increased by the transformation of smectite to illite at increasing temperature and depth. As water is expelled from the clay crystal lattice, pore pressure increases.

Artesian systems. In these systems, the surface elevation of the well is below sea level or below the water table. This commonly occurs when drilling in a valley or basin surrounded by hills or mountains—locations where a connected water table is charged by water from higher locations.

Fracture migration. Fault planes may allow pressure transmission from a zone of higher pressure to a more shallow, lower-pressured zone. This results in an abnormally pressured, or charged, sand. These effects are common in tectonically stressed environments and adjacent to salt domes.
Reflection tomography offers significant advantages compared with conventional seismic data. Conventional seismic data processing smoothes out velocity fluctuations, and velocity interval picks are often too coarse for accurate pore-pressure prediction. Reflection tomography replaces the low-resolution, conventional velocity analysis with a completely general ray-trace modeling-based approach. Although an interpretable image might be obtained using a relatively poor but smooth conventional seismic-velocity field, the resolution is sometimes too low to accurately predict pore pressure for well-planning purposes. By contrast, the tomographically refined velocity model leads to better understanding of the magnitude and spatial distribution of pore pressure, reducing the uncertainty of pore-pressure predictions (above).

Reducing Uncertainty

In areas where the geology is unknown and where few, if any, wells have been drilled, seismic geopressure prediction may be the only planning tool available to the engineer. However, data from multiple sources, especially drilling, can be used in conjunction with seismic tomography to refine models, and reduce risk and cost, while improving drilling efficiency.

Once wells have been drilled, drillers and planning engineers have access to additional data, including mud records, mud logging information, formation samples, wireline and while-drilling logs, and formation test data. Tools such as the MDT Modular Formation Dynamics Tester sample formation fluids and provide accurate reservoir pressures.

Pressures in shale sections above a reservoir can be estimated based on offset-well mud weights. Daily drilling reports of problems such as kicks, lost circulation, differential sticking and other drilling problems also may indicate the presence of abnormal pressures. Planning engineers generally use offset-well data cautiously. Using mud weights to estimate formation pressure may be misleading, particularly when the data come from older wells.

Most wells are drilled in an overbalanced condition, with mud weights that exceed actual formation pressure by 1 lbm/galUS [120 kg/m³] or more. Drillers frequently increase mud weights to control troublesome, or sloughing, shales.

A more detailed evaluation of geopressure can be obtained by combining drilling data with offset-well electric, acoustic and density logs. To predict pore pressures from wireline or while-drilling logs, analysts often correlate changes in shale porosity with the potential presence of abnormal pressure. This is possible because shales generally compact with increasing depth in a uniform manner. Because of this compaction, the porosity and electrical conductivity decrease at a uniform rate with increasing depth and overburden pressure. However, if a seal is present, higher than normal levels of conductive connate water may be present, increasing conductivity and indicating abnormal pressure (next page, top). Although conductivity is a good indicator, many variables such as connate-water salinity, mineralogy, temperature and drilling-mud filtrate may also affect electric log response.

Acoustic velocity derived from sonic logs provides another tool for determining pore pressure that is less affected by wellbore conditions. Acoustic tools measure the time it takes for sound to travel a specified distance. As formation characteristics change, so do the velocity and the interval transit time.

Shales with porosities approaching zero may transmit sound at velocities on the order of 16,000 ft/s [4,880 km/s] and transit times of 62.5 µs/ft [205 µs/m]. Shales with higher porosity have more pore space filled with...
formation water, hydrocarbons, or both. At 30% porosity, the velocity drops to 12,700 ft/s [3.87 km/s], and the interval transit time increases to about 103 µs/ft [338 µs/m]. Normally pressured shales exhibit decreasing interval transit times with depth. However, as increased pore pressure is encountered, the trend will reverse (below right).

Density logging tools also help engineers predict geopressures. The tool irradiates a formation with gamma rays that interact with the electrons surrounding the borehole. The intensity of the backscattered gamma rays varies with bulk density. Since the bulk density of abnormally pressured shale is less than the density of normally pressured shale, engineers can combine predictions made by density, electric and acoustic measurements with surface seismic data to better refine models and reservoir pressure profiles.

Improving Pore-Pressure Predictions in the Veracruz Basin

Inaccuracies in pore-pressure prediction may lead to well-control problems, exposing an operator to undue risk and excessive cost. Drilling problems in the Veracruz basin, offshore Mexico, led the operator, Petróleos Mexicanos (PEMEX), to reevaluate pore-pressure predictions.12 Engineers at PEMEX and Schlumberger found that predicted mud weights in the Cocuite field were higher than required, resulting in loss of circulation and significant cost overruns. To improve drilling efficiency and reduce risk, engineers and geoscientists used previously acquired three-dimensional (3D) surface seismic data along with sonic logs, mud weights, checkshot surveys and pressure tests from offset wells to improve pore-pressure predictions.13

11. The unit µs means microsecond, or one millionth of a second.
13. Drillers often perform downhole seismic measurements to provide data for correlation of surface seismic data to actual downhole conditions. A checkshot measures the seismic traveltime from the surface to a known depth in the well. Compressional, or P-wave, velocity of the formations encountered in a wellbore can be measured directly by lowering a geophone to each formation of interest; sending out a source of energy from the surface of the Earth, and recording the resultant signal. The data are then correlated to prewell surface seismic data by correcting the sonic log and generating a synthetic seismogram to confirm or modify seismic interpretations. Mechanical earth models and pore-pressure predictions can then be updated.

Electric log analysis to reduce the uncertainty of seismic-based pore-pressure predictions. In normally compacted sediment, electrical conductivity will decrease with depth as water is squeezed from pore spaces. A deflection in conductivity from the normal trend (dashed circle, left and middle) may indicate a change in pore-water concentration, hence the potential for abnormal pressure. Using both seismic and electric log data, computer processing refines the data and generates three-dimensional predictive models that help engineers and drillers visualize pore-pressure trends (right).

Acoustic logs for pore-pressure prediction. Sound waves slow when encountering rock with higher pore-water concentrations. The top of an abnormally pressured zone can be predicted based on the change in interval transit time (dashed circle, right), then correlated to changes in conductivity (left). Both measurements can then be used to reduce the uncertainty of the seismic pore-pressure cube (center).
Before pore pressure can be estimated from seismic velocities, local knowledge of the total vertical stress must be obtained. In the area covered by the Cocuite 3D seismic survey, the only density log available was from Well Cocuite 402, covering a depth range of 643 to 7,690 ft [196 to 2,344 m]. To estimate the overburden stress to the required depth of more than 13,000 ft [3,962 m], density data from the Cocuite 402 density log were combined with other density information from the Veracruz basin into a composite density log. This information was then used to calculate a general overburden stress gradient for the area. Calculated formation velocities were verified by comparing them to sonic logs upscaled to seismic wavelengths and to seismic interval velocities obtained by inverting traveltome depth pairs from checkshots.

Although reasonable agreement was found over the intervals for which sonic logs and checkshots were available, variations in the velocity field from location to location were observed (below). Similar variations were seen for the other wells in the study area. To mitigate these small-scale variations, geoscientists smoothed the velocities laterally before converting the seismic interval velocities to pore pressure. This technique results in 3D models with a high data density that are less uncertain than those acquired with conventional techniques.

Using seismic velocities from the Cocuite 3D survey and a velocity-to-pore-pressure transform, engineers optimized drilling operations by adjusting mud weights. Engineers believe that further refinement in this pore-pressure prediction is possible using reflection tomography to enhance lateral resolution of the seismic velocities.\(^\text{14}\)

**Adjusting Pore-Pressure Predictions While Drilling**

The progression from conventional seismic pore-pressure prediction to reflection-tomographic techniques significantly reduced uncertainty and improved the accuracy of pore-pressure estimates. However, drilling deep into the Earth continued to be fraught with uncertainty.

During well construction, drillers strive to balance mud weight and formation pressure, often based solely on indirect measurements or indicators. Real-time drilling parameters are closely monitored for changes in penetration rate, gas shows and the condition of cuttings returning to the surface, along with signals transmitted from measurements-while-drilling (MWD) and logging-while-drilling (LWD) tools.

Schlumberger geophysicists developed a technique for updating uncertainties in the predicted velocities and pore pressures while drilling.\(^\text{15}\) This technique evaluates uncertainties in the predicted pore pressure on the basis of
The process involved establishing baseline uncertainties in the coefficients of the velocity to pore-pressure relationship from compressional-wave velocity and density. When drilling began, uncertainties were completely defined by baseline values (above).

As drilling progressed on the first evaluation well, a checkshot survey provided data for velocity structure calibration, allowing geophysicists to refine baseline projections and decrease the uncertainty in velocity and pore-pressure predictions. A relatively small decrease in velocity uncertainty resulted, due to the small size of the checkshot dataset, which comprised traveltime measurements acquired at variable intervals of 50 to 200 m [164 to 656 ft].

After initial logging, engineers incorporated sonic log data to further refine the pressure profile. This additional information markedly reduced velocity uncertainty and gave a correspondingly more detailed pore-pressure prediction. The improved pore-pressure predictions lead to more accurate pressure management and enhanced safety during drilling operations.
prediction continued to have a level of uncertainty that could be reduced only by incorporating measured pore-pressure data. In the absence of direct pore-pressure measurements, mud weight was used to represent pore-pressure boundaries.

On the second test well, relatively low velocities were inferred from surface seismic data below 1,500 to 2,000 m [4,921 to 6,562 ft], corresponding to predicted overpressure. Geophysicists incorporated sonic log data to reduce uncertainty. Although pore-pressure predictions improved, the inclusion of mud weights and direct pore-pressure measurements calibrated the coefficients in the velocity to pore-pressure relationship and placed an upper boundary on the predicted pore pressures.

Initially, the pore-pressure gradient from 1,500 to 2,000 m was estimated to be above 13 lbm/gal US [1,560 kg/m³], using pore-pressure predictions based solely on surface seismic data, checkshot values and sonic logs. With the inclusion of MDT pore-pressure measurements, the calibrated pore-pressure prediction constrained the equivalent pore pressure to less than 13 lbm/gal US. Uncertainty was reduced, allowing drillers to better control mud weights, define casing points and improve overall drilling efficiency.

Measuring Reservoir Pressures
After drilling, concerns regarding pressure usually switch to reservoir management and production operations. Understanding pressures in the reservoir ultimately impacts production and payout, and today may even provide guidance to place additional wellbores for optimized production. Operational demands dictate how and when pressure measurements are performed, with many methods and tools being available to measure and monitor reservoir pressures at almost any time during a well’s life cycle. As described above, the understanding of pressure begins with predrill estimates from seismic data and offset wells, and is further refined during drilling. Reservoir and production engineers make additional measurements using logging tools or permanent sensors in the well or at surface.

Some of the many ways reservoir engineers use precise pressure measurements are for fluid identification and typing, defining fluid contacts and assessing reservoir continuity. Obtaining the required measurement precision involves use of services such as the MDT tool, the PressureXpress reservoir pressure while logging service or while-drilling formation-pressure tools. In these services, high-quality data are obtained by allowing time for pressure stabilization before the measurement, by allowing sufficient time for the pressure within the tool to equilibrate with the pressure in the formation and by obtaining a large number of pretests to establish fluid gradients.

Later, in mature reservoir environments where substantial production has taken place, formation-pressure measurements are used to quantify depletion, to assess pressure support or to further analyze reservoir continuity. Even though the accuracy requirements of pressure measurements may not be as strict in mature reservoirs, the ability to measure pressures over a wide range of formation permeabilities may be critical for increasing hydrocarbon recovery.

While-Drilling Pressure Measurement in Norway
Although borehole seismic techniques have brought the driller closer to understanding and predicting pore pressures in real time, scientists and engineers continue to develop tools for obtaining direct pressure measurements while drilling. As LWD technology advanced, engineers adapted the CQG Crystal Quartz Gauge and strain-gauge pressure sensor technologies used in other pressure tools, such as the MDT system, to real-time, while-drilling, pressure-sensing tools (see “Quartz Pressure Sensors,” next page).

Engineers at Statoil and Schlumberger field tested the new StethoScope formation pressure—while-drilling service in 2004 in several fields located offshore Norway. The goal of field testing was to establish whether a while-drilling formation-pressure measurement could be of comparable quality to wireline MDT tester measurements given the range of permeabilities, well conditions and mud properties encountered in these fields.

All formation tester tools measure pore pressure at the interface between the external filtercake and the wellbore wall, or sandface. Whether or not the pressure at the sandface is a good estimate of the true, far-field formation pressure depends not only on the properties of the mud, the filtercake and the formation, but also on the drilling-fluid circulation-rate history.

If the filtercake is totally ineffective in sealing between the formation and test probe, then wellbore pressure will be measured; if the filtercake provides a perfect seal, given sufficient time, the tester should measure the true formation pressure.

In most drilling situations, filtercakes are neither perfect nor uniform in composition. During the course of normal drilling operations, the filtercake is eroded by mud circulation, scraped away during trips, and then rebuilt at the borehole face. Laboratory experiments with both water-base and oil-base muds indicate that dynamic wellbore conditions influence the mudfiltration rate into the formation and, by implication, the pressure measured at the sandface. A leaking filtercake is frequently a problem and may result in significant differences between measured and true formation pressures. When the difference between the measured sandface pressure and the true formation pressure is significant, the formation is usually said to be supercharged. This situation may occur in both while-drilling and conventional wireline-conveyed methods of measurement, but may be more common in a while-drilling method due to the dynamic environment.

To improve confidence in pressure measurements, the StethoScope tool was designed with a pressure-measurement probe embedded in a stabilizer blade surrounded by an elastomeric sealing element, or packer (previous page). The stabilizer design maximizes the flow area at the cross section of the probe, diverts the flow away from the probe-to-formation interface, and minimizes the mud velocity in the vicinity of the probe, thereby helping to reduce filtercake erosion and filtrate leakage into the formation while testing. A drillable setting piston is employed to push the stabilizer containing the probe against the formation face.

The tool draws power from a downhole MWD turbine. Additional power is provided by a battery, capable of fully operating the formation-pressure-while-drilling tool, for example during tests, when the pumps are off. Sandface pressures are measured by two drilling-qualified pressure gauges: a proprietary, ruggedized CQG pressure sensor and a strain-gauge sensor. A second strain-gauge pressure sensor, located near the probe, measures wellbore pressure continuously. All data acquired during formation tests are stored in tool memory, including pressures, temperatures, actual pretest volumes and drawdown rates, and tool-related state and

Quartz Pressure Sensors

Quartz is one of several minerals that display piezoelectric properties. When pressure is applied to a quartz crystal, a positive electrical charge is created at one end of the crystal and a negative charge at the other. Quartz crystals are also strongly pyroelectric; temperature changes cause the development of positive and negative charges within the crystal.

A correctly cut quartz crystal has a resonant frequency of vibration, similar to a tuning fork. As the quartz vibrates, there is a detectable sinusoidal variation in electrical charge on its surface. Pressure-induced stress applied to the crystal causes the sine-wave frequency to vary in a predictable and precise manner. These properties make quartz valuable in many electronics and sensing applications, including oilfield pressure sensors.

Researchers at Schlumberger-Doll Research in Ridgefield, Connecticut, USA, began work on a highly sensitive pressure gauge based on the unique properties of quartz crystals in 1980, and proposed the dual-mode oscillation concept that became fundamental to the development of the CQG Crystal Quartz Gauge sensor (above right).1 The project was transferred to Schlumberger-Flopetrol, Melun, France, in 1982. The development team was supported by researchers at Ecole Nationale Supérieure de Mécanique et des Microtechniques, Besançon, France.

Pressure sensors are sensitive to temperature and pressure variations, and must be corrected for temperature fluctuations. The CQG gauge improved on previous crystal pressure transducers by providing both temperature and pressure measurements from a single sensitive element, eliminating problems associated with thermal lag between separate pressure and temperature sensors. This sensor produces a small peak error induced by transient conditions. Transient errors are further minimized by a dynamic temperature compensation algorithm based on a simple model of the sensor. CQG sensors operate efficiently at pressures ranging from 14.5 to 15,000 psi [0.1 to 103.4 MPa] and in a temperature range of 77 to 300°F [25 to 150°C].

In 1989, the CQG sensor was optimized for commercial fabrication and applied to numerous oilfield pressure-sensing applications, including the MDT tool. More recently, the CQG sensor was ruggedized for LWD and MWD applications, and today it is the primary pressure sensor in both the StethoScope tester and the PressureXpress tool.

1. Two mechanical oscillation modes are excited and maintained by the electronics in the CQG resonator plate. One is more sensitive to lateral stresses caused by pressure applied on the sensor; the other is more sensitive to temperature variations. These two resonance frequencies provide simultaneous information on pressure and temperature and allow computation of a temperature-corrected pressure measurement.
Parameters are chosen to cover a wide formation-fluid mobility range.

The parameters specify the volumes employed and the duration of the buildups for Pretest 1 (the "investigation" test) and Pretest 2 (the "measurement" test). The graph demonstrates the StethoScope tool response when testing a 1.5-mD/cP limestone formation using a pretest sequence similar to that of fixed-mode Type B. During this test, the second buildup was extended, allowing engineers to observe the pressure stabilization time across a longer than normal test sequence. There is a variance in the sandface pressure measurement when performing the measurement with pumps on (red) at a rate of 1,363 L/min [360 galUS/min], and with pumps off (blue).

In the field-testing stage, offshore Norway, fixed-mode pretests were employed. Four fixed-mode pretest sequences that utilize different preset test parameters are available in the StethoScope tool. Each fixed-mode pretest sequence comprises two drawdown and buildup pairs designed to deliver two stabilized sandface pressures within a specified time frame, generally 5 minutes. When consistent, these two independent pressure measurements per test location, or station, together with an estimate of the formation fluid mobility, give confidence in the final pressure result. Comparison of the two pressures obtained in conjunction with the computed mobility can reveal the effects of a static or dynamic pressure environment. An order of magnitude estimate of the formation fluid mobility is helpful in deciding which particular fixed-mode sequence to employ in any given situation, but there is sufficient overlap in their ranges of application that this decision is not critical.

Communication to and from the tool is by means of the TeleScope high-speed telemetry-while-drilling service, specifically designed to provide increased data rate and bandwidth for data delivery. A special telemetry protocol for use with the Telescope telemetry system allows a single device, such as the StethoScope tool, to monopolize data transmission when it has a large amount of data to transmit over a short time interval. The combination of the TeleScope system and on-demand data transmission allows StethoScope data to be visualized at surface in real time.
During field testing, the performance of the tool in both low-mobility (less than 0.2 mD/cP) and high-mobility (more than 350 mD/cP) formations was evaluated, with most data acquired being compared with wireline MDT pressure data and cores. Tests were conducted in a vertical well, highly deviated wells (up to 75°) and a horizontal well, with circulation rates ranging from pumps off to 2,300 L/min [600 galUS/min]. To assess the effects of time elapsed since drilling, pressure measurements were taken from one hour to 43 hours after the bit penetrated the test depth. While-drilling pressures were compared with those obtained with a MDT tester up to 24 days after the while-drilling measurements.

Field tests in Norway established that real-time pressure measurements made by the StethoScope tool are comparable to those made by wireline MDT testers under similar permeability, mud type and borehole conditions. In general, the most accurate pressure measurements were obtained in formations with the highest mobility, with pumps off, or when using a circulation rate that was as low and as constant as possible, and while tripping out of hole (right). Measurements made during the drilling process should be repeated at selected stations while tripping out to confirm the pressure values obtained, especially if supercharging is suspected.

Engineers determined that for formations having fluid mobilities below 5 mD/cP, there is a distinct advantage to acquiring sandface pressures with pumps off. The degree of supercharging as a function of circulation rate depends directly on the amount of time since the filtercake was mechanically disturbed. High circulation rates can promote the erosion of an established filtercake, yielding supercharged sandface pressures even after a lengthy period between drilling and the pressure test. It is not always safe to assume that the supercharging effect decreases with time during drilling. Time-lapse data are important in identifying dynamic supercharging in formations with low mobilities.

The field test conducted by Statoil and Schlumberger in the North Sea yielded positive results. The StethoScope tool demonstrated its ability to accurately measure formation pressures in real time without needing to orient the tool or incurring excessive nonproductive time. In formations where the mobility is sufficiently high, 5 mD/cP or more, the StethoScope measurements are of the same quality as those acquired with the MDT tool. Today, both tools are helping engineers, geologists and drillers quickly make decisions, reduce drilling uncertainty and save time and money.

While-Drilling Reservoir Pressure in the Gulf of Mexico

In deepwater drilling and production environments, operators strive to reduce risk, uncertainty and cost. An example is the Ram Powell Production Unit, operated by Shell Offshore. Covering eight blocks in the Viosca Knoll area, eastern Gulf of Mexico, USA, wells are located in 2,000- to 4,000-ft [609- to 1,219-m] water depths, about 125 miles [200 km] east-southeast of New Orleans. Production began in September 1997, making it one of the most mature deepwater oil fields in the Gulf of Mexico.

Five commercial sands between 5,500- and 13,500-ft [1,676- and 4,114-m] subsea true vertical depth (TVD) are responsible for most of the Ram Powell production. Geologists and engineers reevaluated the field between 2001 and 2003, including time-lapse seismic surveys that identified potentially undrained infill-drilling opportunities.

In January 2004, Shell initiated redevelopment activities. Engineers found a high degree of risk and uncertainty in the new drilling projects. New well targets required drilling complicated directional wells. Production had also depleted several pay sands, rendering them unstable and difficult to drill. Although these circumstances made formation evaluation more difficult, the added uncertainty increased the need for formation evaluation while drilling.

To reduce cost and improve efficiency, Shell and Schlumberger engineers planned to use LWD and MWD technologies to evaluate the reservoir and drilling environment in real time on Well 2 of the redevelopment campaign. Engineers selected a bottomhole assembly (BHA) consisting of a PowerDrive Xtra rotary steerable system, a suite of 6.75-in. VISION Formation Evaluation and Imaging While Drilling tools, and the StethoScope tool components—all positioned below a hole opener. The VISION suite included an arcVISION675 6/8-in. drill collar resistivity tool, an adnVISION675 6.75-in. Azimuthal Density Neutron tool and a proVISION675 6.75-in. nuclear magnetic resonance (NMR) tool. The TeleScope telemetry service provided real-time data transmission and control.

Engineers planned to use the pressure data acquired by the StethoScope tool for completion design and to verify dynamic reservoir models. Obtaining formation pressure measurements while drilling reduced both rig cost and borehole exposure times, and allowed reservoir engineers and geologists to make timely well-placement decisions.

After the driller set 11 3/4-in. casing at 10,474-ft [3,192-m] measured depth (MD), the initial 10 5/8-in. hole section was drilled at an inclination of about 45° from 10,514- to 15,688-ft [3,205- to 4,782-m] MD. Shell's petrophysicist selected the formation pressure-measurement points using data from the density neutron tool to determine the location of target sands. When on station, the StethoScope tool automatically began a drawdown-wait-retract sequence. After each pressure measurement, the probe was retracted and the tool was moved to the next station. On-station time averaged 10 minutes or less per measurement.

Real-time formation pressure measurements showed good pressure support within the reservoir and confirmed that the low-resistivity zone at the bottom of the target sand was swept oil, indicating a higher than expected oil/water contact. Using this real-time data, Shell engineers decided to sidetrack the well. The new hole was placed higher in the reservoir by drilling updip from 11,501- to 16,952-ft [3,506- to 5,167-m] MD at 58° inclination. The pressure measurements

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\begin{array}{c|c|c}
\text{Sidetrack Formation Pressure} & \text{Hydrostatic Pressure} & \text{Depth} \\
200 \text{ psi per division} & 30 \text{ psi per division} & \\
\hline
0 & 0 & 0.6 \\
1 & 20 & 6 \\
2 & 30 & 12 \\
3 & 40 & 18 \\
4 & 50 & 24 \\
5 & 60 & 30 \\
6 & 70 & 36 \\
7 & 80 & 42 \\
8 & 90 & 48 \\
9 & 100 & 54 \\
10 & 110 & 60 \\
11 & 120 & 66 \\
12 & 130 & 72 \\
13 & 140 & 78 \\
\end{array}
\]
confirmed good connectivity within the reservoir, so casing was run to total depth.

The proVISION675 NMR data helped engineers calibrate net-sand calculations and improve the petrophysical evaluation of laminated sands. Combining while-drilling data from NMR with data from other LWD tools provided important information on rock texture, permeability, grain size and net sand. NMR fluid-property data were used with formation pressure and fluid mobilities to estimate formation permeability.

In total, 26 pressure measurements were made—13 while drilling the initial section and 13 while drilling the sidetrack. Pressure measurements provided critical information for making sidetrack and completion-design decisions. Pressures were successfully acquired in both massive and laminated sands (previous page).

Advances in MWD technologies now provide pressure and fluid-mobility measurements that were previously available only with wireline logs. Engineers can perform complex evaluations based on MWD data alone, significantly reducing the risk, cost and uncertainty of drilling deepwater development wells.

Engineers estimate that formation pressure while drilling and associated measurements saved more than US$1 million by eliminating the need for two conventional drillpipe-conveyed pressure-measurement runs. In addition, while-drilling NMR data provided important information regarding fluid viscosity and rock texture for net-sand calculation as well as permeability and grain-size estimations, which were used in the completion design. Shell plans to continue using pressure-while-drilling and other real-time technologies to improve efficiency and reduce risk, particularly on challenging deepwater projects.

Quick and Precise Reservoir Pressures
Wireline-conveyed formation-testing measurements have long been recognized as key to collecting essential information to help identify fluids in place, pressure regimes and dynamic properties of a reservoir. Although they measured formation pressures accurately, previous techniques required that a wireline tool be stationary for relatively long periods of time while testing the formation. This is particularly true in low-mobility zones where longer evaluation times increase the cost and risk of tool sticking.19 Now, reservoir engineers have options that provide fast and accurate pressure measurements. Tools such as the PressureXpress service quickly make multiple, highly accurate pressure measurements.

Engineers at the Schlumberger Riboud Product Center in Clamart, France, integrated advanced versions of the CQG gauge and the Sapphire pressure gauge into the PressureXpress tool. These pressure sensors provide high-resolution pressure measurements, dynamically compensated for temperature (above).

Earlier formation testing tools relied on hydraulically driven pretest systems that were monitored and controlled from surface. The lag time between surface commands and changes in the downhole hydraulic-sampling actuator limited pretest volume control. The system was redesigned, replacing the hydraulic system with an electromechanical motor coupled to a planetary roller-screw mechanism and high-reduction gearbox, greatly enhancing the stability and accuracy of both the pretest rate and volume. Transferring the controls and commands from the surface to the downhole electronic cartridge improved the response time, making it possible to achieve pretest volumes as low as 0.1 cm³ (0.006 in.³).

Formation testers have traditionally been run alone or on the bottom of a wireline toolstring, because of their inability to pass the telemetry of other wireline tools. Implementation of new through-wiring hardware and a new software telemetry system now permits combinations with all other wireline tools, which can be run anywhere above or below the new tool.

Through 2004, the PressureXpress service was field-tested on a total of 57 jobs, and more than 1,300 pretests were performed, in a wide variety of environments, including sandstone and carbonate formations. These involved formation fluids varying from gas to heavy oil under steam recovery. Bottomhole temperatures ranged from approximately 100 to 310°F [38 to 154°C], at hydrostatic pressures of 0 to 13,000 psi [0 to 90 MPa].

Engineers incorporated the Smart Pretest dynamically controlled intelligent pressure testing system to automatically find the best possible compromise between the formation-produced volume and the pressure-buildup time. In formations with fluid mobilities greater than about 1 mD/cP, the new tool can perform a pressure and mobility test in less than one minute: this represents an improvement of as much as four to five minutes over other testers.

In tight formations, the pretest system can select fluid volumes as low as 0.1 cm³, allowing minimal test times.

In some areas of Texas, tight gas-bearing sandstone reservoirs may have permeabilities ranging from a few microdarcies to tens of millidarcies. In these fields, gas production relies on hydraulic fracturing to provide the conduit for reservoir flow. Many of these areas are mature and partially depleted, resulting in large pressure differences between reservoir layers. Determining these pressures accurately is key to optimizing hydraulic fracturing programs.

Failed attempts to measure pressures with conventional tools led to fracturing the entire reservoir thickness, including depleted zones, resulting in unnecessary completion expenses and lost production. For one well, Schlumberger engineers used the PressureXpress service; 58 pretests were attempted and 56 formation pressures were measured in less than seven hours. Data obtained from the testing program identified zones in the mid-reservoir section depleted by as much as 4,000 psi [27.6 MPa], while the last 500 ft [152 m] of pay was still at a

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relatively high pressure (below right). Engineers designed a four-stage hydraulic-fracturing stimulation procedure. Six fewer stages were pumped than on previous wells, yet production increased by more than 50%, saving the operator more than US$ 400,000 in fracturing costs.

Managing Reservoir Pressures
Geopressures drive oil from a reservoir to a producing wellbore. As production starts, a pressure drop in the formation around the wellbore causes oil to flow through pore networks in the reservoir toward the point of withdrawal. With oil withdrawal and subsequent pressure drop in the reservoir, the oil, water and rock expand. Changes in pressure, expansion and movement of all these materials influence oil production.

Once a reservoir is producing, engineers and geophysicists use various techniques to monitor the movement of fluids and changes in pressure. Recent advances in seismic imaging allow acquisition of 3D surveys over time, known as time-lapse or four-dimensional (4D) seismic surveys. Understanding the movement of fluids and changes in reservoir pressures allows engineers to better model reservoir behavior and improve recovery efficiency.

From a purely mechanical point of view, geopressure data are relatively simple to obtain during or shortly after drilling. As discussed earlier, real-time, while-drilling pressure tools, such as the StethoScope system, are providing engineers with valuable geosteering and reservoir data for completion design, while wireline-conveyed tools, such as the PressureXpress service, provide accurate pressure and mobility data shortly after the well is drilled. But, there is a problem: once casing is run into the well, these tools cannot access the formation where there are no perforations. Thus with time, known pressures become unknown, and production decisions become more uncertain.

Using sensors similar to those mounted in while-drilling and wireline pressure tools, Schlumberger engineers designed the CHDT Cased Hole Dynamics Tester, capable of measuring pressure and extracting fluid samples from behind a cased wellbore.  

An electromechanical pretest system to reduce time on station. At time 0 s, the PressureXpress tool is on station and because it is not yet set, the flowline pressure is reading the wellbore mud pressure, approximately 4,430 psi [30.5 MPa] (black square, left). The tool is then hydraulically set, corresponding to an increase in the hydraulic pump velocity (green). The pressure curve (black) measures a pretest drawdown in a 0.01-mD/cP formation at about 45 s, followed by a gradual pressure buildup. After about 200 s, the tool initiated a second pressure drawdown (red triangles), extracting a volume of 0.1 cm³ of fluid from the formation. From 280 s to 680 s, reservoir pressure stabilized, then the tool was hydraulically retracted from the formation (green curve), and the flowline pressure increased to the wellbore mud pressure. By using an electromechanical motor, the pressure-testing tool accurately controls the pretest volume and rate at low values (0.1 cm³), effectively reducing buildup duration and time on station.

Identifying depleted zones. Formation pressures (red) are compared with the mud gradient (green), identifying zones depleted by as much as 4,000 psi [27.5 MPa] in the middle part of the reservoir, while the last 500 ft of pay is still at a relatively high pressure.
The CHDT tool can drill through casing and cement and then into the formation, take multiple pressure measurements, recover fluid samples and plug the holes made in the casing, all in a single descent (above). The ability to reseal the drilled holes makes the tester uniquely suitable for several reservoir and production applications: for example, locating bypassed hydrocarbons, evaluating unknown pay zones, producing or injecting through a few holes, and determining formation-evaluation parameters when no openhole logs are available. Engineers can then optimize recompletion plans, enhance old or incomplete log data, assess unknown pay zones and evaluate wells for economic potential. The tool reduces rig cost by eliminating the costs of conventional plug-setting and cement-squeeze operations.

An operator in south Texas requested an evaluation of a well drilled in 1941. Cased-hole logging tools identified multiple zones with potential hydrocarbons. Engineers used a USI UltraSonic Imager device to evaluate casing condition and cement quality, and then the CHDT tool to measure reservoir pressure and confirm fluid type.

During the test, seven formation pressures were acquired. Four samples confirmed hydrocarbons. The CHDT tool successfully plugged all holes. Based on test data, the operator was able to plan a recovery program for the bypassed hydrocarbons.

Even though engineers can evaluate reservoir pressures behind casing long after production has begun, running tools in the hole is a costly, invasive procedure. Well problems are addressed most efficiently when acted on quickly. Developments in downhole telemetry, pressure sensors and advanced completion systems offer the reservoir engineer the flexibility to make production decisions in real time.

Permanent downhole pressure sensors and monitoring tools, such as the WellWatcher real-time production monitoring and surveillance system, provide a continuous source of downhole pressure measurement throughout the life of a well. Most often placed in the wellbore along with completion hardware, permanently installed sensors constantly monitor production pressures (next page). When these sensors are used with other real-time monitoring hardware such as fiber-optic temperature sensors, engineers can constantly update reservoir models and optimize the complete reservoir system.

Before the introduction of these systems, data acquired through well intervention provided only a snapshot of well performance at the time the parameters were measured. Now, highly reliable downhole monitoring systems are sustainable in most downhole environments.

The WellWatcher system has been in place on 15 BP North Sea assets for more than eight years. From 1995 through 2003, BP installed 75 of the monitoring systems in platform and subsea projects, all based on permanent pressure sensors. BP reports that during this period, only four of the systems have failed, translating to a success rate of 95%.

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^ Cased-hole sampling tool. Engineers use the CHDT tool to make multiple pressure measurements and collect fluid samples from behind a cased wellbore. Powered by a wireline cable, the backpressure pads (lower side of tool) push the tool into an eccentric position (tool shown eccentered against blue casing frame), the probe (shown tool top side) seals against the casing, and then drills a hole and measures pressure, samples fluids and plugs the hole. As the drill bit penetrates the target, the onboard integrated instrument package monitors pressure, fluid resistivity and drilling parameters.
In the BP Madoes field, a satellite of the Eastern Trough Area Project (ETAP) in the central North Sea, three producing wells are tied back 12.5 miles [20 km] to the primary platform. During completion, field specialists installed a FloWatcher integrated permanent production monitor system in each well to monitor pressure, temperature, absolute flow rate and fluid density in oil-water flows. Real-time data from the monitoring system allowed BP production engineers to quickly react, slowing water production by reducing production rate. If they had relied only on surface measurements, the problem would have been much worse.

Engineers involved in the Foinaven deepwater subsea development, West of Shetlands, North Sea, are using real-time pressure sensors to better understand reservoir flow dynamics, adjust gas lift rates and maximize production. Prior to real-time downhole pressure measurements, engineers relied on modeling software to help optimize gas lift rates and hence, overall production rate. These models required data from costly and time-consuming well tests and generally provided results with limited accuracy. Real-time downhole pressure monitoring systems now allow BP engineers to adjust gas lift rates to achieve minimum flowing bottomhole pressure, and hence maximum production rates.

Additional value is derived from the ability to track well performance based on establishing baseline parameters early in well life and then taking periodic time-lapse measurements of permeability height and skin factors from analysis of buildup pressure transients. This has provided early identification of well-performance problems, allowed more detailed evaluation and permitted intervention approaches to be optimized, with associated time and cost savings.

The Foinaven team has also used the data from permanent downhole sensors to significantly improve understanding of reservoir connectivity, and then optimize various water injection and associated voidage replacement strategies. Engineers involved in the project estimate that over a three-year period, beginning in 2000, the combined benefit of these monitoring systems accounted for 1 to 3% of incremental production.

Data from continuous real-time sensors provide engineers with the necessary information to optimize reservoir performance and recovery by detecting problems early and defining timely, preemptive reservoir-management solutions.

Managing the Pressure System
Maintaining reservoir pressure and optimizing recovery of oil and gas have become parts of a global challenge. The measurement of pressure throughout a reservoir’s life cycle is key to reservoir management. Accurate and efficient pressure measurement helps engineers and geophysicists manage subsidence, improve sweep efficiency in secondary-recovery operations and improve asset performance.

Case histories demonstrate that engineers can refine predrilling seismic pore-pressure models using downhole data, then adjust models with real-time data allowing wells to be drilled more quickly with reduced cost, improved borehole placement and better management of the reservoir. As efforts continue to define the next energy revolution, reservoir engineers, geologists and geophysicists are combining the current developments in pressure-measurement tools with advances in seismic interpretation and modeling to optimize recovery and extend the life of known hydrocarbon reserves. — DW

Highly complex sensor and control installation. As downhole control-system technology evolves, the complexity of completion, monitoring and control systems continues to increase. Multizone completion systems comprising packers, sand-control screens, flow-control valves (WRFC-E) and sensor packages for temperature, pressure, resistivity and more are not uncommon.