The KTB Borehole—Germany’s Superdeep Telescope into the Earth’s Crust

The drill bit has stopped turning and the KTB project is winding down. Germany’s superdeep borehole is complete. How and why was it drilled? And what have the scientists achieved so far?

Thermal gradients, heat production, stress fields, fluid transport, deep seisms and deep resistivity are all of great interest to earth scientists. Studying these fundamental topics helps them unravel the mysteries of weather fluctuations, the distribution of mineral resources, and natural disasters such as earthquakes, volcanoes and floods. Rock outcrops, river gorges and cliff faces provide visual evidence to interpret deep probing measurements such as seisms, magnetics and gravimetics. Commercial mining and drilling have also guided scientists, giving tangible connections to surface observations (above). However, drilling has been used specifically for scientific research only within the last thirty years.

The internationally funded Ocean Drilling Program (ODP) was started as part of a worldwide effort to research the hard outer layer of the Earth’s crust called the lithosphere. Results from this project have been dramatic, providing real evidence of continental drift and plate tectonics. The lithosphere is made up of six major and several minor rigid moving plates. New oceanic crust is formed and spreads out at mid-ocean ridges and is consumed at active plate margins—subduction zones—where it sinks back into the Earth’s mantle. This process takes up to a few hundred million years.

Continents are different. They are made of lighter rock and are not easily recycled,
allowing them to achieve ages of 4 billion years. They also provide the vast majority of the world’s resources, so it is vital to understand their structure and development. One way of doing this is to extend the work started by ODP to the continent. KTB—which stands for Kontinentales Tiefbohrprogramm der Bundesrepublik Deutschland, or German Continental Deep Drilling Program—is drilling one of a handful of boreholes specifically for continental scientific research. This article looks at the major drilling achievements of KTB, at the Schlumberger wireline logging contribution and at some of the main areas of research.

The project was initiated in 1978 by a working group of the German Geoscientific Commission of the German Science Foundation. The group discussed more than 40 possible drill sites in Germany, eliminating all but those with the broadest possible research potential. Two sites were chosen for further studies: Haslach in the Black Forest region of South Germany and Windischchenbach 80 km [50 miles] east of Nürnberg in Bavaria, southeast Germany. In 1985, the Federal Ministry for Research and Technology gave the final approval for the KTB deep drilling program and both sites were comprehensively surveyed.

Both geology and the expectation of a lower formation temperature gradient favored the Windischchenbach site. The site is located on the western flank of the Bohemian Massif about 4 km [2.5 miles]
east of a major fault system—the Franconian line (left). Scientists also believe it lies at the boundary of two major tectono-stratigraphic units in Central Europe—the Saxothuringian and Moldanubian. This boundary—which they hoped to cross—is regarded as a suture zone formed by the closure of a former oceanic basin 320 million years ago. This process gave rise to a continent-continent collision—forming a mountain chain and the present-day Eurasian plate. The mountains have long since eroded away, exposing rocks that were once deeply buried. Therefore, this area is ideal for the study of deep-seated crustal processes. In addition, geophysical surface experiments have shown that the area around the drill site has unusually high electrical conductivity and strong gravimetric and magnetic anomalies, which deserve closer investigation.

The scientific challenges for the KTB project all contribute towards understanding the fundamental processes that occur in continental crust. Among these are earthquake activities and the formation of ore deposits. The primary objectives, therefore, were to gather basic data about the geophysical structure below the KTB site, such as the magnitude and direction of stresses, so that the evolution of the continental crust might be modeled. Information about thermal structure—temperature distribution, heat sources and heat flow—was also needed to understand chemical processes such as the transformation to metamorphic rock and the mineralization of ores. Fluids also play an important role in temperature distribution, heat flow and the various chemical processes, so measurements of pressure, permeability and recovery of fluids found were also important.

The overriding goal of the KTB project was to provide scientists with a permanent, accessible, very deep hole for research. With a budget of 498 million Deutsche Marks [$319 million]—provided by the German government—the initial target was to drill until temperature reached about 300°C [572 °F]—expected at a depth of 10,000 m to 12,000 m [32,800 ft to 39,370 ft]—the estimated limit of borehole technology. This includes drilling hardware, drilling fluid chemistry, cementing as well as the downhole instrumentation required for the various scientific experiments. Many technical spin-offs developed from the project.
Drilling the Vorbohrung—Pilot Hole

It is not common to drill through surficial crystalline rock especially when the drilling conditions are unknown. Kola SG 3, on the Kola peninsula near Murmansk, Russia, is one exception. It is the world's deepest borehole, but not an ideal role model (right). After 15 years of drilling, at an untold cost, the borehole reached a depth of 12,066 m [39,587 ft]. Years later it was deepened to 12,260 m [40,200 ft].

The project management team, having studied the Russian project, decided to first drill a pilot hole—KTB Vorbohrung (KTB-VB). This was spudded on September 22, 1987. The objectives for the pilot hole were as follows:

- Acquire a maximum of geoscientific data, from coring and logging the entire borehole, at low cost and minimum risk before committing to an expensive heavy rig and superdeep hole.
- Minimize core runs and logging in the large-diameter, straight vertical upper section of the superdeep hole.
- Analyze the temperature profile for planning the superdeep hole.
- Obtain data about problem sections with inflow or lost circulation, wellbore instabilities and breakouts.
- Test drilling techniques and logging tools in preparation for the superdeep hole.

To accomplish these objectives, a new drilling technique was developed that combined rotary drilling and sandline core retrieval techniques (right). A modified land rig used a high-speed topdrive to rotate internal and external flush-jointed 5 1/2-in. outside diameter mining drillstring in a 6-in. borehole. This drillstring provided enough clearance inside to allow 4-in. cores to be cut and pulled up to surface through the drillpipe by sandline—eliminating round trips to recover cores. A solids-free, highly...

3. Massif is a block of the Earth's crust bounded by faults or flexures and displaced as a unit without internal change.
4. A tectono-stratigraphic unit is a mixture of lithostratigraphic units resulting from tectonic deformation. The Saxothuringian is a low pressure-high temperature unit still showing sedimentary structures. The Moldanubian is a low pressure-high temperature unit with relics of two older phases of higher pressure. The sedimentary structures have almost disappeared.

Sandline coring technique. Four-in. cores are cut with high-performance, impregnated diamond core bits (1). As the cores are cut, they slide inside the core catcher barrel (2 and 3). When coring is complete, the drillstring is picked up off bottom to break tree the core (4). A rig line and latching tool are run through the drillstring and latched onto the core barrel. The barrel is pulled out-of-hole through the internally flush mining drillstring (5). A new core barrel is run back into the drillstring and landed above the core bit to continue coring.
The lubricating mud system had to be used, because of the small clearance between the flush external surface of the drillstring and the borehole wall. This coring method worked well until February 1989 when excessive corrosion in the pipe joints required replacing the mining string with conventional 3½-in. externally upset drillpipe and core barrels.

Coring operations had to be interrupted on other occasions—three times for directional drilling to bring the hole back to vertical and twice for sidetracking, because of lost bottomhole assemblies after unsuccessful fishing. However, a total depth (TD) of 4000 m [13,124 ft] was reached for KTB-VB on April 4, 1989, after 560 days of drilling and logging. More importantly, 3594 m [11,790 ft] of cores were recovered—a recovery rate comparable to those achieved worldwide in easier formations—and the hole was extensively logged with many different instruments (left and next page).

The drilling experience in KTB-VB proved invaluable to the planners of the superdeep borehole. For example, they encountered areas of borehole instability across fault zones; they had to modify the mud system to account for water influx and water-sensitive rock; they had numerous breakouts caused by the relaxation of stressed rock; and the formation dipped more steeply than predicted making it difficult to keep the hole anywhere near vertical. In total, the pilot hole presented a greater challenge for drillers than expected.

For the next year, many experiments and measurements—such as hydrofracs, production tests and extensive seismic work—were carried out in and around KTB-VB. In April 1990, the hole was finally cased and cemented. Meanwhile, plans continued for construction of a new rig to drill the superdeep borehole about 200 m [656 ft] away.

Logging tools used by KTB. The logging tools listed in the tables were run in the pilot hole (KTB-VB) and the superdeep hole (KTB-HB) and were provided by various logging companies, universities and institutes. KTB bought several tools, some of which were developed for the project.
### Other Companies’ Logging Tools

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<th>Company</th>
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<th>KTB-VB</th>
<th>KTB-HB</th>
<th>High Temp.</th>
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3 Now part of Schlumberger Geco-Prakla

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### University and Institute Logging Tools

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Drilling the Hauptbohrung

The superdeep hole—KTB Hauptbohrung (KTB-HB)—was spudded on October 6, 1990, and reached a TD of 9101 m [29,859 ft] on October 21, 1994. To drill to this depth in only four years required the design and construction of the largest land rig in the world—UTB 1 (left).6 This rig could handle 12,000 m of drillpipe that required a maximum hook load of 8000 kN [1,800,000 lbf]—more than three times that of the rig used to drill KTB-VB. Mechanical wear and tear was expected to correspond to drilling 30 deep conventional wells, with over 600 round trips. Reducing trip time called for radical rig design. Using 40-m [130-ft] stands of drillpipe instead of the standard 27-m [90-ft] stands saved 30% of the time. However, long drillpipe stands meant the rig had to be 83 m [272 ft] high.

To further increase trip efficiency, an automated pipe handling system was installed (right). This consisted of a 53-m [174-ft] high pipehandler that grasped and lifted stands of drillpipe between the rotary table and star-shaped fingerboard for stacking in the derrick. Pipe connections were made by an iron roughneck that replaced traditional pipe-spinners and make-up tongs. Automatic slips gripped the pipe in the rotary table as connections were made and hydraulically operated elevator clamps did the derrick man's job. More time was saved as pipes were connected or disconnected by retracting the traveling block out of the way as it traveled up or down the derrick. This allowed the pipehandler to operate while the traveling block was moving.

The entire operation was controlled by a driller, pipehandler operator and two floormen. Only the floormen worked outside on the rig floor—the other two sat inside a control room at consoles equipped with video screens and gauges (next page, top). Computers controlled many of the operations of the pipehandler. Using a pipe conveyor to lift single pipes between rig floor and pipe racks saved additional time.

Borehole torque and drag as well as the strength of the drillpipe are decisive factors when it comes to reaching great depths quickly and safely. Torque while drilling and excessive hook loads when pulling the string are caused by lateral forces and friction between drillstring and borehole wall. These two factors are increased by the weight of drillstring, borehole inclination and severity of any doglegs. Borehole trajectory influences not only drillstring design,
**Armchair drilling.** The driller, surrounded by instruments and video monitors, controls drilling operations from the comfort of a control room overlooking the rig floor. The driller is joined by the pipehandler operator when pipe is tripped in or out of the borehole.

**Vertical Drilling Systems (VDS).** The VDS systems consist of positive-displacement motors to drive the drill bits, battery-powered inclinometers to measure deviation, and hydraulic systems to steer the drill bit. Any drift away from vertical is measured by the inclinometer and fed back to the hydraulic system. Two steering systems were developed. The first holds extendable ribs against the formation using mud pressure (left). Deviation corrections are made by releasing pressure in one rib, causing the whole assembly to move towards that rib. The second system is steered internally (center). Pistons move the gimbal-mounted rotating shaft, which is connected to the bit, to make any deviation adjustments. Another variation, VDS-4, reverted back to extendable ribs (right). (Courtesy Baker Hughes Inteq.)
Lithology comparison between KTB-VB and KTB-HB and an overview of drilling and casing KTB-HB. The differences in lithology between the two boreholes—which are only 200 m apart—highlight the complex structure being drilled (left). Drilling difficulties required cement plugs to be set to correct for deviation and for sidetracks to be drilled after unsuccessful fishing operations (middle). Extra casing strings had to be run to protect crumbling borehole (right).
The VDS system consisted of a positive-displacement motor to drive the drill bit, a battery-powered inclinometer to measure deviation and a hydraulic system to adjust the angle of the drill bit to correct for deviation. Two hydraulic systems were used: the first system operated external stabilizer ribs that pushed against the borehole wall moving the whole VDS assembly back to the vertical; the second system used internal rams to move the shaft driving the drill bit back to vertical. As long as battery power was maintained to the inclinometer, both systems operated automatically. Inclination, and other parameters such as temperature, voltage and systems pressure, were transmitted to surface by a mud pulser to monitor progress.

The first 292 m [958 ft] of KTB-HB were drilled with a 17 1/2-in. bit and opened up to 28 in. before setting the 24 1/2-in. casing (previous page). To meet the requirements of a vertical hole, a 2.5° correction to deviation was made as the hole was widened. The next section was drilled with a 17 1/2-in. VDS system to 3000 m [9840 ft] and completed at the end of May 1991. Teething problems with prototype VDS systems meant using packed-hole assemblies (PHAs) during maintenance and repair. Even so, average deviation for this section was less than 0.5°.

The same strategy was used for the 14 1/4-in. hole—alternating between the improving VDS systems and PHAs. A high deviation buildup from 3519 to 5596 m [11,522 to 18,360 ft] during one PHA run led to the borehole being pulled back and a correction made for deviation. The hole continued on course to 6013 m [19,728 ft] where 13 5/8-in. casing was set in April 1992—horizontal displacement at this stage was less than 10 m [33 ft].

Drilling continued with VDS systems and PHAs and 12 1/4-in. bits. Within this section 45.7 m [150 ft] were cored, including 20.7 m [68 ft] with a newly developed, large-diameter coring system that gave 9 5/8-in. diameter cores. However, in July 1992 at 6760 m [22,179 ft], the bit became stuck. Eventually, after an unsuccessful fishing operation, the hole had to be plugged back to 6461 m [21,198 ft] and sidetracked. In March 1993, over an interval of 6850 to 7300 m [22,474 to 23,950 ft], a major fault system was crossed. The VDS system could not control deviation over this interval and another correction had to be made. This system was thought to be an extension of the main fault that lies along the boundary between sedimentary rocks to the west and metamorphic rocks to the east—the Franconian line. Along this fault system a displacement of more than 3000 m occurred, showing a repetition of drilled rock sequences. This signaled the start of the most difficult drilling yet and additional funds had to be provided by the German government to complete the project—bringing the total cost to DM 528 million [$338 million].

At 7490 m [24,573 ft], when the horizontal displacement was only 12 m [39 ft], the VDS system was abandoned, as borehole temperatures became too high for the electronics. The hole then started to deviate north (below). Within the main fault system the borehole became unstable and more breakouts occurred. While tripping out-of-hole from 8328 m [27,323 ft], the drillpipe became stuck at 7523 m [24,682 ft]. Jarring eventually broke the downhole motor housing allowing the pipe to be pulled out but leaving behind a complicated fish. Several attempts to retrieve the fish failed and the hole was finally plugged back to the vertical section—at 7390 m [24,245 ft]—and sidetracked. Drilling again proved difficult and so a 9 5/8-in. liner was set at 7785 m [25,541 ft] in December 1993 to protect this hard-won section of hole.

Difficult drilling continued with a 8 1/2-in. bit down to 8730 m [28,642 ft]. Borehole instability prevented further progress and a 7 7/8-in. liner was set in May 1994. To bypass the unstable section, a sidetrack was made at 8625 m [28,297 ft] through a precut window in the liner. Funds to continue drilling were now running low and a decision was made to stop 476 m [1561 ft] later on October 12, 1994. More than four years after spudding, the hole had reached 9101 m with a final bit size of 6 1/2 in. However, the borehole had not finished with the drillers yet. Attempts to lower logging tools into the open hole failed. The last section had to be re-drilled and a 5 7/8-in. liner set, leaving only 70 m [230 ft] of open hole for the wireline loggers and other scientific experiments.

January 1995
Data Collection and Analysis
The main center of scientific activity at KTB was the field laboratory with a staff of 40 including resident scientists and technicians (see “KTB Logging Center,” page 16). Here, experiments were performed on cores—mainly from the KTB-VB—drill cuttings and gas traces from the shale shakers, sidewall cores from the Schlumberger Sidewall CoreDriller tool, rock fragments from the drillpipe-conveyed cutting sampler and fluid samples collected during pump tests and downhole. The field laboratory provided cataloging and storage facilities and a database of basic information such as petrophysical properties, mineralogy and lithology needed for further experiments (above). More detailed long-term experiments were conducted at universities and research centers in 12 countries.

Nearly 400 logging runs were made in KTB-VB—the pilot hole—with every available borehole instrument (page 8). And 266 runs were made in KTB-HB—the superdeep hole. The wealth of data acquired in the field lab allowed a rare opportunity to calibrate borehole log responses to core data in crystalline rocks—as opposed to sedimentary environments where their response is well known—satisfying one of the main objectives of KTB-VB.

The formations that were cored and drilled consisted of metamorphic basement rocks—principally gneisses and amphibolites. Initially cores and rock fragments—from cuttings—were photographed and cataloged according to depth recovered. Microscopic analysis of thin sections assisted recognition of mineralogy and microstruc-
ture and assignment of rock type.12 By mapping the macroscopic structure and orienting it with borehole logs such as the FMI Fullbore Formation Microlmage image or Borehole Televiewer (BHTV) image, a structural picture of the borehole was gradually built up (previous page, bottom).

Petrophysical parameters, such as thermal conductivity, density, electrical conductivity, acoustic impedance, natural radioactivity, natural remanent magnetism and magnetic susceptibility were also routinely measured. In addition to determining the strength of rock samples, scientists made highly sensitive measurements of expansion of the cores as they relaxed to atmospheric pressure.

Geochemists at the field laboratory performed detailed core analysis using X-ray fluorescence for rock chemical composition and X-ray diffraction for mineralogy.13 This analysis allowed a reliable reconstruction of the lithology.

After comparing logs with cores, scientists at the Geophysical Institute at the University of Aachen were able to distinguish 32 distinct electrofacies corresponding to 32 minerals. This enabled borehole logs to contribute to and refine the lithological profile of the superdeep borehole, established from cutting samples and the limited cores available (right).

One contributor to the success of the logging operation was the GLT Geochemical Logging Tool. This provided concentrations of 10 elements present in rock: silicon, calcium, iron, titanium, gadolinium, sulfur, aluminum, potassium, uranium and thorium. Another tool with a semiconductor detector—germanium—was also used, which gave a higher sensitivity and provided the additional elemental concentrations of sodium, magnesium, manganese, chromium and vanadium.14 By combining the GLT results with other measurements, minerals such as pyrite, pyrrhotite, magnetite and hematite could be quantified.

Older logging techniques also proved invaluable. Abnormal Spontaneous Potential (SP) deflections occurred across mineralized fault systems. Other SP deflections combined with low mud resistivity readings from the Auxiliary Measurement Sonde (AMS) occurred at zones of water influx. When the AMS resistivity showed only mud and the SP showed a deflection, this was regarded as an indicator for mineralization. Uranium tends to concentrate at graphite accumulations so the uranium reading from the NGS Natural Gamma Ray Spectrometry tool was used as a graphite indicator.

(continued on page 19)

11. Gneisses are banded rocks formed during high-grade regional metamorphism. Included in this group are a number of rock types having different origins. Gneissose banding consists of the more-or-less regular alteration of schistose and granulose bands. The schistose layers consist of micas and/or amphiboles. The granulose bands are essentially quartzofeldspathic and may vary from 1 mm up to several centimeters in thickness. There are various types of gneiss depending on the rock origin. Paragneiss is from a sedimentary parent and orthogneiss from an igneous parent. Amphibolite is a metamorphic rock composed mainly of feldspars and amphibole, a group of inosilicates.
The KTB logging center is every wireline engineer’s dream come true. Situated 60 m [200 ft] from the rig, the logging unit is housed in a covered enclosure, providing space for calibration and operation checks of logging tools (above). Portable units off the enclosure provide maintenance workshops for electronics and hydraulic sondes. Several offices are provided for the KTB logging staff and Schlumberger personnel as well as a computer room equipped with a micro-VAX III for interpretation and presentation of results. The offices also provide workplaces for scientists from universities who run their own logging tools into the borehole using the logging unit.

The winch unit houses the CSU wellsite surface instrumentation computer and a silent power pack, which provides hydraulic power for the winch and electrical power for the instruments (next page). The winch is extensively modified to cope with the high cable tensions encountered during logging. A high-strength drum holds around 9500 m [31,200 ft] of cable, and a capstan at the foot of the rig reduces cable tension from a maximum of 90,000 N [20,000 lbf] to a normal spooling tension of 4500 N [1000 lbf]. Other modifications allow additional tensiometers and depth measuring systems to monitor the cable at different points of the rig-up.

The logging cable is permanently suspended in the derrick to save as much rig-up time as possible. The winch is housed in a cellar in front of the logging unit allowing logging cable and ancillary wiring to run through a tunnel below the rig yard exiting at the capstan unit. The cable passes around the capstan before going up the outside of the rig. Here it passes over the upper sheave wheel attached to a retractable jib. When logging is required, the jib is extended out over the rig floor so that logging tools may be connected to the cable and lowered into the borehole. Built into the rig floor is a series of tool magazines. These contain logging tools in a state of readiness to run into the borehole.

Logging at depths of 9100 m [30,000 ft] and temperatures approaching 260 °C requires special hardware—cable, logging head and logging tools—to withstand ultrahigh pressures and temperatures. The cable also has to have the
strength to pull the logging tools back to surface. At 9100 m, the normal logging tension is 67,000 N [15,000 lbf], right on the maximum safe pull for the special high-strength cable used. This cable has high-tensile steel armor wires and is thicker than standard to provide the strength. It has special insulating materials at the business end that allow logging at temperatures up to 260 °C for short periods of time.

If the borehole had gone any deeper, a two-cable approach to logging would have been used. At 10,000 m, the high-strength logging cable would be in danger of breaking under its own weight—even accounting for the buoyancy effect of the mud. To reduce cable weight, a smaller diameter, lighter, high-temperature cable hooked up to a second winch would have been used to lower logging tools into the borehole for the first 3200 m [10,500 ft]. At this depth, the small-diameter cable would be connected to the high-strength cable of the main winch and the journey into the hole continued. With this tapered cable configuration, the overall weight of cable is decreased, reducing the tension, and the high-strength cable is at the top of the hole where the tension is greatest. This technique was used twice, but only with 1500 m [4921 ft] of small-diameter cable. This approach was taken by Russian well loggers to log the 12-km [7.4-mile] Kola borehole using a three-conductor cable.

A special oil-filled logging head was developed by Schlumberger for the KTB project. This had high-temperature feed-throughs and special O-rings, and provided the connection between cable and logging tool.

Although there are several standard high-temperature logging tools available, tools were upgraded especially for KTB. One example is the high-temperature Formation MicroScanner tool, which was upgraded to 260 °C (next page, left). The first task in modifying this tool was to produce a list of components to upgrade. Several components, such as the pads containing the button electrodes, were not changed, but could be used only once. Other components, such as the hydraulic motor that opens and closes the sonde calipers, could still be used more than once. Mechanical maintenance of such high-temperature tools has to be meticulous—using even one component that should have been changed could result not only in a malfunction but also in destruction of expensive equipment.

Temperature limits on the mechanical aspects of the tool were relatively straightforward to overcome. However, the electronics were of major concern. Normally these operate up to 175 °C.
To keep the temperature within this limit meant housing them inside a Dewar flask (below, right). The outside temperature could be as high as 260 °C with the inside remaining below 175 °C for up to 8 hours.

The cooling effects of mud circulation during drilling were calculated to be about 50 °C [90 °F] at TD. When circulation stopped, the temperature would gradually climb, giving a window of 36 hours for logging before it exceeded tool ratings.

On the first logging run at TD, the maximum temperature recorded was 240 °C [464 °F] and on the last run, this reached 250.5 °C [483 °F]—confirming earlier calculations. At the end of each logging run the Dewar flasks were cooled down slowly by blowing air through to avoid thermal shock.

Apart from Schlumberger logging tools, several universities developed equipment for their own experiments in the borehole (see page 9).

High-temperature Formation MicroScanner tool. The tool was developed for KTB and has a temperature rating of 260 °C. Standard electronics—rated to 175 °C [350 °F]—are protected inside Dewar flasks and sealed at the ends by thermal stoppers. Standard mechanical components may withstand this temperature, but the button electrode pads are changed after each logging run.
Surprises—Some Welcome, Some Not
Both boreholes yielded unexpected results for the scientists. Geologists had formed a picture of the crust at the Windischeschenbach site by examining rock outcrops and two-dimensional (2D) seismic measurements. At a depth of about 7000 m [22,966 ft] they had expected to drill through the boundary between two tectonic plates that collided 320 million years ago, forming the Eurasian plate. However, this boundary was never crossed, and the geologists have had to redraw most of the subsurface picture.

Other unexpected results include core and log evidence for a network of conductive pathways through highly resistive rock, and in rock devoid of matrix porosity, an ample supply of water. Look at these findings in more detail:

Seismic Investigations—During the project, surface and borehole seismic measurements helped visualize the structure below the KTB site. The original picture had been formed from 2D seismic work undertaken before drilling. But the structural profile of KTB-VB showed a more complicated subsurface. Instead of a nappe unit, the formation followed a more tortuous path (right).

After KTB-VB was completed in April 1989, a year was spent on major seismic evaluation. The seismic work, under the joint responsibility of KTB and DEKORP—German Continental Reflection Seismic Profiling—was performed by Prakla-Seismos—now part of Geco-Prakla. This included a 3D survey over an area of 19 by 19 km [11.8 by 11.8 miles], vertical seismic profile (VSP) and moving source profile (MSP), using geophones in KTB-VB, and two wide-angle 2D seismic surveys with an offset of 30 km [18.6 miles] using vibrators and explosives as sources. The evaluation, conducted by a number of German universities and their geophysical institutes, utilized acoustic impedance calculated from borehole sonic and density measurements and the acoustic measurements made on cores in the field laboratory. The seismic processing was complicated by the tortuous structure and the large seismic anisotropy. The results, however, gave a much clearer picture than the earlier 2D work and accurately predicted the major fault system drilled through between 6850 to 7300 m (page 6).

It is now known that the borehole remained inside the Zone of Erbendorf Vohenstrauss (ZEV), a small crystalline unit tectonically placed between the Saxothuringian and Moldanubian units. There are indications that these metamorphic units of the Bohemian Massif have been uplifted 10 km [6.2 miles] since Variscan time—about 300 million years ago—and eroded to the present day surface.

Future experiments have been designed to measure seismic anisotropy at greater depths, the spatial extension of seismic reflectors—such as the “Erbendorf” structure at a depth of about 12 km [7.4 miles]—and the detailed velocity distribution between the two boreholes using seismic tomography. Seismologists will also take advantage of the superdeep borehole KTB-HB by recording downhole seismic waveforms emitted by earthquakes. In this way, surface noise will be reduced and the frequency content of the signal preserved.


17. Indications come from the analysis, for example, of detrital muscovites from the sedimentary basin west of the Bohemian Massif and the study of eroded sediments. Typical techniques used in geochronology are the determination of cooling ages by radiometric dating.
Electromagnetics—One of the reasons for choosing the Windischeschenbach site was to investigate the origin and nature of a low-resistivity layer recorded by surface measurements that appeared to be 10 km below the Earth's surface. This is not unique to southern Germany, as similar layers are found in many continents around the world.

To unravel the mysteries of this conductive layer, scientists pursued many different angles. Conductivity measurements on cores from KTB-VB showed high resistivity as expected in crystalline rocks. But then highly conductive graphite-bearing faults and cataclastic zones were found at various depths up to 7000 m [22,970 ft]18. These were also seen on borehole logs where abnormal SP deflections of more than 200 millivolts (mV) coincided with the graphite. Other logs, such as induced polarization—where the decay of a voltage applied at a surface electrode is measured downhole—showed conductive pathways potentially formed by veins of graphite and/or sulfides.

At a much larger scale, when the KTB-HB was at a depth of 6013 m [19,730 ft] a dipole-dipole experiment was carried out. This consisted of using the casing from both holes to inject current into the formation (above, right). The resulting potential field was measured around the borehole. Any changes in potential indicated a connection of an electric conductor to one of the casings, supporting the theory for a conducting layer extending over a distance of several hundred meters. The results showed that the conducting layer coincided with graphite deposits in a north-south striking fault system—the Nottersdorf fault zone. The faults from this system crossed KTB-VB at about 250 m [820 ft] and KTB-HB at about 1500 m [4921 ft].

Further experiments are planned to investigate the depth, thickness, electrical anisotropy and source of the high conductivity layer still believed to be at 10 km.

Stress and Deformation—One of the goals of earth science is earthquake prediction, and ultimately reduction in earthquake risk. The physics of earthquakes requires an understanding of the movement of tectonic plates, the forces involved and role the crust plays in transmitting those forces. Many scientists think that the top 10 km of crust is brittle and carries most of the stress that moves the entire 100-km [62-mile] thick continental plates. They also believe that, with increasing depth, the crust becomes ductile and cannot support the stress. KTB research may help clarify the transition from brittle to ductile.

Preliminary work in the two KTB boreholes has already determined the orientation of the local stress field.19 The four-arm caliper, resistivity imaging tools, such as the Formation MicroScanner tool, and acoustic imaging tools, such as the BHTV, were used to calculate the stress direction from analysis of two types of failure: shear failure of the borehole wall—called breakouts—and drilling-induced tensile failures. The former occur at an azimuth orthogonal to the orientation of the maximum horizontal stress. The latter are near-vertical fractures in the borehole wall in the direction of the maximum horizontal stress (next page, left). These fractures were easily identifiable on the cores cut in the KTB-VB and were oriented using Formation MicroScanner and BHTV images (page 14, bottom). The maximum horizontal stress is oriented to N 150° ± 10° E from surface down to 6000 m [19,685 ft].

To obtain the stress magnitude, hydrofrac experiments were carried out in both boreholes at various depths in conjunction with geoscientists at the Universities of Bochum,

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18. Cataclastic rock is rock that has undergone mechanical breakage usually by dynamic metamorphism or faulting.
Formation MicroScanner images before and after a hydrofrac in KTB-VB. The Formation MicroScanner image recorded after the hydrofrac clearly shows near-vertical induced fractures around an azimuth of about 150°.

and Karlsruhe, Germany and at Stanford University, California, USA. By fracturing the formation, the minimum and maximum principle stresses were determined.

These and earlier tests in KTB-VB confirmed that the strength of the rock was increasing with depth, supporting the theory that the upper crust is strong enough to carry most of the stress of tectonic movement. Very recently, a hydrofrac experiment was carried out at 9000 m [29,528 ft] and is being evaluated.

Thermal Studies—Of the many processes occurring within the continental crust, most are temperature dependent. Mapping the temperature distribution and measuring heat production, heat flow and thermal conductivity are therefore a vital part of understanding these processes. During the initial temperature mapping, KTB-VB held the unwelcome surprise that the formation temperature gradient was higher than anticipated. This disappointing result meant that 300 °C—the set limit of current technology—would be reached at about 10,000 m—much shallower than originally predicted.

Temperature measurements were carried out in the two boreholes during regular logging campaigns (above). These were used to estimate true formation temperature. The borehole is cooled during drilling, by up to 70 °C [158 °F] in the deepest sections of KTB-HB. Formation temperature is obtained by recording several temperature profiles at preset time intervals as the hole heats up again and extrapolating these profiles to infinite time on a logarithmic plot.

Each temperature profile was recorded during the first wireline logging run. This helped avoid another complication, disturbing the mud temperature profile by the logging tools. A wireline tool was even modi-
fied at KTB with the temperature sensor mounted on the bottom of the tool to provide the least disturbance and give the best possible result.

Temperature data provided an opportunity to measure heat production and conductivity. In addition, thermal conductivity measurements were carried out in the field laboratory on cores cut from the boreholes. From the NGS and Litho-Density data, heat produced by radioactive decay was calculated—for metabasites the results were 0.5 micro-Watts per cubic meter (µW/m³) and for gneisses 1.6 µW/m³.

The final temperature profile has yet to be extrapolated from the data obtained so far. Experiments will continue to examine temperature distribution, heat production, heat flow and thermal conductivity.

Fluids—The scientists at KTB expected deep crystalline rock to be bone dry, but to their surprise, water influx occurred at several depths from open fractures.

Sonic, Formation MicroScanner and BHTV data were used to detect the fractures. As fresh mud was used for drilling, any saline water inflow would cause a decrease in mud resistivity. This could easily be seen from mud resistivity measurements made by the AMS tool (above right). These zones were allowed to produce by dropping the mud level, enabling a fluid sample to be collected by a wireline-conveyed sampler run in combination with the AMS tool. Tests showed the water had not leached down recently from surface. Further tests will be performed to ascertain the origin and composition and investigate fluid-rock interaction.

During a two-month pumping test 275 m³ [1730 bbl] of salt water were produced from an open fracture system at the bottom of KTB-VB. Further evidence showed the extent of the fluid network. During a production test at 6000 m in KTB-HB, the fluid level in KTB-VB dropped. When the 13 ½-in. casing in KTB-HB was cemented, there was an increase in fluid level in KTB-VB. These two events confirmed hydraulic communication and allowed an estimate of permeability of the fracture system between the two boreholes.  

Natural causes of fluid movement became apparent when pressure sensors deployed in KTB-VB recorded changes in pressure due to earth tides caused by the gravitational pull of the moon.

Fluids play an important role in the chemical and physical processes in the Earth’s crust, influencing mineral reactions, rheological properties of rocks and melting and crystallization processes. To aid further scientific research into these processes long-term pumping tests are planned between KTB-HB and KTB-VB to measure hydraulic communication, identify fluid pathways and collect additional fluid samples.

The Future for Superdeep Boreholes
In 1996, the KTB boreholes will be handed over to GeoForschungsZentrum (GFZ), a German government-sponsored geoscientific institute based in Potsdam, Germany. GFZ will continue the work started by KTB and the site will become a laboratory for deep measurements. Although the rig will be dismantled, the derrick will remain as a monument to KTB’s achievements. These achievements have inspired scientists all over the world to look again at superdeep boreholes with renewed enthusiasm. Many potential sites whet the appetite: the San Andreas fault zone, California, tops the list for studying earthquake activity; for volcanic studies, the Novarupta Vent in Alaska, USA; subduction zones at the Izu peninsula, Japan or the Hellenic subduction zone, Crete; and there is no larger continental collision zone than the intracontinental thrust in the Nanga Parbat region of the Himalayas. It is now up to scientists to convince governments to support international continental scientific drilling with the necessary funding. —AM

Imagine breaking your leg and having an X-ray, only to be told that the image won’t be ready for interpretation for a year or more. Until recently, seismic surveys suffered from similar delays. But thanks to breakthroughs in acquisition, processing and communication, 3D seismic turnaround time—time from the first shot to the beginning of interpretation—has been reduced from years to weeks.

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There are two main reasons oil and gas producers worry about the time spent on 3D seismic acquisition and processing, called turnaround time. First, in the oil and gas business, as in every business, time is money. The more time spent on drilling, logging and well completion, the longer the delay in production and the lower the profit. Add the time to acquire and interpret seismic data before drilling, and the delay in bringing reserves to the surface may grow beyond the schedules and budgets of many production managers.

Second, and special to the oil and gas business, saving time can make the difference between being able to do business and not. Development contracts worldwide require oil companies to drill within a specified time. The clock starts ticking once acreage is licensed. A 3D seismic survey planned, acquired, processed and interpreted in advance arms developers with tools for intelligent well placement, yielding higher production from fewer wells.

More 3D seismic surveys are also being commissioned for exploration, in addition to field development, their initial application. Unlike 2D seismic, which grew from the exploration market into development, 3D seismic has grown in the opposite direction. Companies are discovering that early acquisition of 3D data reduces finding costs and overall project costs. Interpreted seismic data are essential for intelligent bidding on acreage. And some exploration contracts now require a 3D survey before drilling. This expansion into exploration, along with decreases in the cost of seismic acquisition and processing, has raised demand for 3D seismic data.

This increased demand has forced service companies to reduce turnaround time—without sacrificing quality. This article looks first at the dramatic improvements in marine turnaround time, then at the steps being taken to significantly reduce turnaround in transition zone and land surveys.

The Marine Story
Three years ago, a marine survey of 500 km² [193 sq miles] took a year or more to be acquired and processed. Today, through a combination of new technologies, turnaround time for similar surveys can be as little
Technologies responsible for this dramatic reduction vary from faster acquisition capacity to high-speed links with shore-based computers for real-time, full-scale processing (left). Today seismic vessels can acquire data 12 times faster than they could in the early 1980s, thanks to multielement acquisition—multiple air gun sources, multiple receiver streamers and even multiple vessels. Prior to 1984, vessels towed one source array and one 3-km [1.9-mile] streamer (next page, bottom). This configuration evolved to two streamers and two sources per vessel by 1986, quadrupling the area covered with each traverse, and decreasing the cost per unit area. In 1990, streamer length started to increase, also as nine weeks (above). Technologies responsible for this dramatic reduction vary from faster acquisition capacity to high-speed links with shore-based computers for real-time, full-scale processing (left).


decreasing costs. By 1991, there were two sources firing alternately to three streamers, and by 1992, there were four streamers. In 1994, the Geco Gamma acquired the world's first survey with six streamers. And in a continuing quest for greater capacity, contractors are now building or refurbishing seismic vessels to tow 8 to 12 streamers.

A challenge in designing vessels for multi-streamer acquisition is to keep all the streamers uniformly separated while maintaining vessel speed. Streamers are separated with a deflector, which steers outer streamers away from their normal stream lines (right). Most streamers follow angled slabs—paravanes—which deflect the streamer outward, but also create drag on the vessel. Each 3-km deflected streamer may exert up to 12 tons of drag, forcing the vessel to consume more fuel to maintain speed. Eight to twelve streamers, with paravanes deflecting the outer ones, would act like a sea anchor, creating enough drag to stop an ordinary vessel. One contractor, PGS Exploration, is designing a more powerful vessel to address this problem.

Rather than design a larger, more expensive vessel to tow more streamers, Geco-Prakla has designed the Monowing deflector. Acting like an airplane wing flying through water, this “lifts” the streamers apart, and results in a 500% increase in lift-to-drag ratio compared to conventional deflectors. The reduced drag increases acquisition efficiency, and also safety. The lower tension in the lead-in, or tow cables, between the vessel and the streamers, reduces the chance of a tow cable snapping and flapping back to hit the vessel. And unlike other deflectors, orientation of the Monowing can be controlled remotely, to act as a rudder for the streamer. This allows streamer spacing to be controlled from the vessel, and permits individual streamers to be spooled in for repairs. The Monowing deflector has already been deployed in the Irish Sea and West Africa, to tow six streamers. It is being tested with five streamers at extra-wide 150-m [492-ft] spacing, making the 600-m [1980-ft] swath acquired in a single vessel pass the widest ever.

Streamers themselves have also been upgraded. In earlier, analog streamers, hydrophones were wired to the streamer cables and the analog signal transmitted up the streamer and then digitized. There may have been signal leakage in the streamer, or cross-talk, in which a signal from one hydrophone gets mixed with that from another. With digital streamers, the signal is recorded digitally so cross-talk is eliminated. Digital streamers are also more reliable, resulting in less downtime and better turnaround.
While multielement acquisition has played the leading role in reducing acquisition time, it has created a new challenge in reducing overall turnaround time. Data can arrive at a staggering 5 MBytes/sec and some of it must be processed before the next shot is fired—about every 10 seconds—if the processing is to keep pace. Rising to the challenge is concurrent processing, a combination of onboard processing and high-speed communication with onshore computers and decision makers.

To achieve minimum turnaround time, two sets of data—source signature quality and survey position—must be processed between shots. The source is a cluster of different-sized air guns. On Geco-Prakla vessels the air guns are controlled by the TRISOR module of the TRILOGY integrated acquisition and processing system. This module fires the air guns in a sequence that is tuned to their sizes. As the size of the gun increases, so does the time from firing to maximum pressure. The TRISOR controller synchronizes the guns’ pressure maxima, giving a stronger source signal.

TRISOR hardware also monitors source output to check the quality of each shot.

TRISOR sensors, located within one meter of the air guns, communicate with the vessel through fiber-optic connections, and are packaged based on concepts from Anadil’s measurements-while-drilling (MWD) technology. In this hostile environment, near a high-energy source and sustaining at least 500,000 shocks per year, the rugged construction that ensures reliable MWD also helps reduce seismic turnaround.

To maximize vessel uptime, errors such as a gun going off at the wrong time, or not at all, must be detected immediately. Then processing specialists can determine whether the shot must be retaken, or whether the recorded signal satisfies the geophysical objectives of the survey. If the signal is sufficient, time is saved. If insufficient, time is still saved, because a seismic line can be quickly reshoot while the vessel is still over the survey area.

The second set of data that must be processed between shots is survey position coordinates, called navigation data. Navigation data describe the position on the earth of every source and receiver point in the 3D survey. The data come from relative position measurements made with every shot as the vessel is in motion. The position of the vessel relative to satellites is determined using the Global Positioning System (GPS). Geographic positioning with GPS is a relatively new technique, more reliable and available than traditional radio positioning, and can fix locations to within two meters. The in-sea positions of the seismic sources and receivers are computed using directions from compasses mounted on the streamers and distance information—ranges—provided by acoustic sensors and lasers distributed in networks across the ends of the streamers (left). The TRINAV module of the TRILOGY system collects the compass, laser and acoustic signals, detects transit times, processes them for range, computes the network node positions, calculates source and receiver positions and stores the results in a data base before the next shot is fired. The number of sensor data measurements—including compass data, laser ranges and bearings, satellite and radio position signals—used in such a calculation has grown from 15 in the days of single source and single streamer, to more than 350 now with dual sources and eight streamers (next page, bottom).

Checking that the positions fall within the project specifications is a daunting task, and one whose automation has further reduced turnaround time. Until recently, this was done subjectively by navigation analysts, visually checking plots and position listings. Now, computed positions are quality assured using position acceptance criteria (PAC), automating the time-consuming task and slashing weeks off turnaround. The PAC are established by comparing the range in question to the range of the last shot. If the two are within a predefined threshold, the range is accepted. Deviations are flagged by the computer, making them easy to spot.

As recently as 1993, some contractors made range measurements during acquisition and calculated rough initial positions, but waited until their return to shore to verify the calculations and link—merge, in seismic-speak—the seismic data traces with the corresponding source and receiver positions. Three years ago, contracts typically allowed six to eight weeks for this process, but a difficult job could take six months. Now, the final position data can be made available in three hours (left).

While navigation data are being collected and processed, the seismic traces are beginning their journey through data processing. Essentially any processing offered by onshore processing centers can be supplied onboard. The entire processing chain is too elaborate to detail here. But a few key steps, and how they are being streamlined to help reduce turnaround, are examined in the following case study.

A Turnaround Breakthrough

In the summer of 1994, Statoil, in partnership with Saga and Mobil, conducted a 3D turnaround pilot project in block 33/6 of the Norwegian North Sea (above). The area had already been traversed with 2D lines. The acreage covered in the 3D survey was an extension of a play concept that had proven prolific to the south—the oil basin contains the Statfjord field, estimated at more than 3.5 billion barrels of recoverable oil, and the Snorre field. The 33/6 area will be part of concession round 15, recently announced by the Norwegian government. With this survey already acquired, processed and interpreted, the oil companies, acting individually, can make better decisions about how to bid for acreage.

The goal of the pilot project was to turn around the 313-km² [120-sq mile] survey in seven weeks. With conventional technology, such a survey would take 18
weeks: 6 for acquisition, then at least another 12 for processing. Executing such a tightly constrained survey requires exact planning. Survey design, acquisition parameter selection and choice of processing chain were given special attention by Statoil and Geco-Prakla geophysicists. In addition to these standard steps, during the planning phase it was recognized that to minimize turnaround time, both Statoil and Geco-Prakla would have to reevaluate accepted working practices: Statoil agreed to hold decision-response time to 12 hours, and Geco-Prakla agreed to increase computer and communication resources that would allow more rapid acquisition and processing.

The Geco-Prakla vessel, *Geco Gamma*, was equipped with the latest technology for the job. *Gamma* had the TRILOGY system for onboard navigation and seismic data processing, and access to INMARSAT, the international marine satellite system. Three IBM RISC 6000s were installed to handle the near real-time processing, reproducing the software and hardware of an onshore processing center. The data would travel directly from the acquisition system to the memory of the TRIPRO onboard processing system. The plan called for crucial data to be transmitted via satellite and land lines to the Statoil office in Stavanger, Norway, where a work-

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Examples of low-frequency (left) and high-frequency noise (right) detected with onboard processing. Low-frequency noise is caused by ocean swells during bad weather. High-frequency noise is caused by reverberations between sea surface and sea bottom, enhanced at particular water depths.

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Noise level of survey data, before (left) and after filtering (right). High-level noise related to bad weather appears as red and orange bands along sail lines. Noise concentrated in one area, but spanning several lines (yellow upper left), is generated by a change in subsea topography. After filtering (right), the noise is still apparent, but within acceptable limits.
station was installed with the same processing and interpretation software.

The first shot was fired on June 22, 1994, with the vessel towing two air gun clusters and four 3000-m [9840-ft] streamers spaced 75 m [246 ft] apart. The survey was 11 km [6.9 miles] wide and was completed in 38 vessel passes, making 293 lines. Some of the first lines were shot in bad weather, which created low-frequency swell noise, above the tolerance level set in the presurvey plan (previous page, top). When that level is exceeded, many oil companies choose to shut down acquisition, and the vessel stands by, at up to $30,000 per day, waiting for weather to calm. But onboard processing showed that the noise could be filtered out, though the filtering would have to be done prestack (right). By monitoring signal quality onboard, and processing the acquired, subspecification data in real time, Geco-Prakla geophysicists were able to decide that the processing scheme would tolerate the noisier data (previous page, bottom). This eliminated the need to reshoot five or six lines, saving $70,000. The savings paid for the added cost of equipping the vessel with the RISC 6000s, and cut two days off the turnaround.

Early in the planning, the team considered undertaking onboard processing of reduced-fold data. But tests conducted prior to acquisition indicated that the reduced fold would give inadequate imaging of subsurface reflectors, so full, 30-fold data were processed onboard (right).

One of the crucial phases of the survey was the construction of the earth velocity

6. Stacking is the summing of traces with reflections that have a common subsurface point. The number of traces summed is called fold. Stacking reduces the amount of seismic data by a factor of the fold and increases signal-to-noise ratio. Processing takes longer when performed on prestack data, because of the greater data volume.

Effects of fold—the number of traces summed to create one stacked trace—on stack quality. In the survey design stage, Statoil and Geco-Prakla geophysicists considered processing lower-fold data to speed turnaround, but tests showed that only full-fold data would give acceptable results. Stack processing run on test lines shows that 4-fold stacking gives low signal-to-noise ratio and unclear reflections (top). Increasing the stack to 12-fold improves the visibility of reflections, but does not adequately suppress reverberations, called multiples, in the lower part of the section (middle). Full-fold, or 30-fold stacking, produces a high-quality section (bottom).
model that would be used to stack and later to migrate the data. Geco-Prakla geophysicists analyzed velocities on 18 seismic lines selected at 500-m (1640-ft) intervals, and transmitted their results via satellite to Stavanger (above). Statoil geophysicists loaded the data on workstations in their offices and worked weekends to monitor data quality and relay decisions on the quality of the velocity picks back to the vessel. A velocity model for the 3D volume was then built onboard.

The last major step before stacking—3D dip moveout processing (DMO)—was also completed onboard for the 30-fold data. This process corrects for the reflection point smear that results when events from dipping reflectors are stacked (right). The final stack volume was being built as soon as the last shot was fired, and inline migration begun while the vessel was steaming back to port.

The computers and processing specialists were flown to Stavanger, where the final processing was completed three weeks later. Data quality was equivalent to that of a normal onshore processing job, and no immediate reprocessing was scheduled. Seven weeks after the first shot was fired, a Charisma workstation-ready tape was produced, waiting to be interpreted (next page).

Onboard velocity picking and quality control. Stacking velocities computed by onboard processing are displayed as contours, the peaks of which can be identified in an interactive velocity picking window (A, black squares). Picks from the previous location are white squares, and picks from the next location are pink squares. Seven time-velocity curves, called velocity functions, are plotted as black curves. The picked velocities, applied to one common midpoint gather before stacking, yield flat reflections (B). The seven velocity functions are applied to one gather, yielding seven panels. The velocities are correct when they give clear, flat reflectors (C). Overlaying the stacked section on a color plot of the velocity field provides a quality check: changes in velocity coincide with major reflections (D).

Fasttracks and Quicklooks
Reduced-turnaround surveys are evolving rapidly, and the amount of processing that goes into each survey varies. Specialists divide reduced-turnaround surveys into two categories: fasttracks and quicklooks. Fasttracks are fast, fully processed surveys, like Statoil’s 33/6. Quicklooks are surveys that process a subset of the full data set—called low-fold—or that simplify processing, such as skipping dip moveout processing.

Quicklooks give interpreters a head start on interpretation, allowing earlier exploration or development decisions and identifying areas that deserve more detailed processing. BP Exploration has conducted four such surveys offshore Vietnam with Geco-Prakla, using onboard processing of navigation, low-fold data and widely spaced streamers to speed turnaround. In one case, BP had farmed into a prospect—taken over a license relinquished by another operator—with only two years remaining. At the time, the planned 3D survey would have taken six months for full-fold processing, compared to 11 weeks for a low-fold interim data cube. By getting the data earlier, BP interpreters were able to spend more...
time understanding the prospect before the spud date deadline.

Quicklooks can be considered preliminary or intermediate results, with potential to benefit from later reprocessing. One example is a 700-km² [270-sq mile] exploration survey shot and processed onboard by Geco Resolution for Mobil in Papua New Guinea. Only portions of the survey were processed with full fold, saving some of the exploration money for drilling and development.

Today, quicklooks and fasttracks alike are possible only if the onboard processing sequence is nearly set in stone during presurvey planning with tests on prior 2D data. If acquisition conditions require processing modifications, some, such as noise attenuation, can be accommodated during the survey.

Further reductions in turnaround will come from improvements in all stages of acquisition and processing. Geco-Prakla researchers are looking into improved algorithms for navigation and seismic data processing. New, high-density data storage media now being introduced will mean fewer tapes created, and speed data transfer wherever tapes are required.10 The wider availability of high-speed communication links such as LINK 100, which enabled the fast turnaround of the Statoil 33/6 survey, will make shorter turnaround the norm rather than the news. Geco-Prakla’s LINK 100 telecommunication service uses very small aperture terminal (VSAT) satellite technology to transmit data to office-based users via leased land lines or SINet, the Schlumberger Information Network.11 However, the greatest potential for improvement in 3D turnaround, lies not in marine seismic, but in land and shallow-water, or transition zone (TZ), environments.

The Onshore Challenge
Today, turnaround for 3D land and TZ surveys can be only unfairly compared with that for marine surveys. The main difference is in acquisition, which in some cases may take 50 times longer on land than at sea.

There is also little formal data on the trends in turnaround for land and TZ surveys, because no two surveys can be compared. In the relatively constant marine environment, where every survey has roughly the same sources, receivers, subsurface and acquisition geometry, surveys of different sizes and from different areas can be scaled up or down for the purposes of keeping statistics. However, on and near land, every survey is different, and turnaround comparisons from one area to another may be meaningless. The environment may vary from swamp to arctic tundra, from desert to jungle. Sources, receivers and acquisition geometries come in as many combinations as there are environments. But in spite of the absence of statistics, land and TZ turnaround are improving.

Paralleling improvements in marine turnaround, TZ and land surveys are seeing more reliable acquisition hardware, faster acquisition through multiple sources and more receivers, and real-time verification of source and receiver positions. The following two sections describe case studies—first transition zone, then land—to demonstrate some of the latest techniques to shorten turnaround.

7. Migration is a processing step that uses earth velocity information to position reflections at their true locations.
10. Helical-scan magnetic tape—also known as VHS-format video tape—can store 25 GBytes on a cartridge, and will soon be able to store 365 GBytes.
11. SINet is managed by Omnes, a joint venture between Schlumberger and Cable & Wireless.
Transition Zone

The North Freshwater Bayou in southern Louisiana, USA, was the site of a 3D survey demanding exceptional turnaround (right). The acreage covered leases operated by Unocal and Exxon. Unocal was drilling at the time of the survey, and planned at least one additional well. Drillers, heading for a deep target below 4.0 sec two-way travel time, wanted to confirm the location of the target before reaching total depth. The challenge was to complete acquisition between the July 15 end of the alligator breeding season and the October 15 start of duck migration—a 13-week window of opportunity.

Survey planners designed a 79-sq mile [200-km²] survey to be processed in two phases. Processing began on an 18-sq mile [46-km²] priority area, while acquisition continued over surrounding acreage.

The shallow-water environment allowed an all-hydrophone acquisition. Some TZ surveys cross the line between water and land, and require a combination of receivers—geophones on land and hydrophones in the water. Processing such surveys takes extra steps to account for the different responses of the various receiver types.

The hydrophones used in the North Freshwater Bayou were attached to the Digiseis-FLX system, a new, flexible transition zone acquisition system developed by Geco-Prakla (bottom). Each Digiseis-FLX data acquisition unit (DAU) is a floating instrumented tube, tethered to an anchor and connected to four hydrophone groups (next page, top). Up to 1536 channels have been recorded in real time without reaching the limits of the system. This large number of channels allows for flexibility in arranging source-receiver combinations, often without moving the DAUs. Seismic data are transmitted to the acquisition boat using radio frequencies that can be adapted to avoid conflict with other radio activity.

The Digiseis-FLX system presents advantages over other TZ equipment, called bay cable. Bay cable consists of a 1/3-in. [0.8-cm] diameter instrumented cable, two to three miles long, that lies on the sea bottom. The cable can shift with currents, and can be damaged by boat propellers and sharp coral. While radiotelemetry avoids these problems, the added flexibility creates a new problem, synchronization: each unit must record at exactly the same time. The Digiseis-FLX system uses a patented synchronization method, achieving an accuracy significantly higher than other radiotelemetry systems.

Another innovation that contributes to the speed of the survey is the method with which the source explosives and the hydrophones are emplaced. The technique—ramming—is like using a hypodermic needle to inject a source or receiver into the earth. Ramming sources in soft transition zone cuts down on the time required to drill
source holes. On land, drilling crews typically drill 100- to 180-ft [30- to 55-m] deep shot holes in advance of the acquisition crew. Equivalent results are obtained with 40- to 50-ft [12- to 15-m] deep ram holes. Ramming not only takes less time, but it also costs less. Deep holes cost about $300 per hole to drill, while ramming costs about $75 per hole. Ramming hydrophones to a uniform depth of 20 ft [6 m] below sea level results in better receiver coupling and higher quality data. The main limitation of ramming is the restriction to unconsolidated earth.

Not all the North Freshwater Bayou turnaround speed came from fast acquisition. Geometry verification—much like navigation data processing in the marine environment—carried out in the field, cut weeks off the normal processing time. Geometry verification, a feature of the Voyager mobile data processing system, checks that the source and receiver positions attributed to every shot record are correct. Usually this is checked back at the office after acquisition has been completed and the crew has left, but fixing errors after the fact is time-consuming. In some cases, entire land surveys have had to be reshot—a turnaround nightmare.

One error typically encountered in geometry verification is a mistake in the identification of shot-point location. This can occur when the source, say a vibrating truck (vibro for short) is at the wrong location, can’t get to the right location, or if the location is missurveyed. It can also occur if receiver locations are missurveyed, or if the wrong receivers are active.

These mistakes can be detected quickly by applying some simple processing at the base camp, after the day’s acquisition (left). The process is called linear moveout, or LMO. LMO compares arrival times recorded for a given source-receiver geometry to those expected for the same geometry, assuming a constant velocity subsurface. If the source and receivers are in the right places, the
LMO process yields seismic traces with first arrivals aligned in time. Any other pattern of first arrivals indicates a mistake in the source-receiver geometry (below).

This technique was used in the Unocal survey to quickly verify geometry in the field. Catching errors with the crew still on site permits corrective action. Shot and field. Without this field verification, errors may be detected weeks or months later. Then, processing specialists would have to test several possible geometries in hopes of discovering what really happened, spending time and money and location input to LMO processing. The flat arrival times indicate warped first arrival times (top). The next day, the shot point was resurveyed, and the new location input to LMO processing. The flat arrival times indicate correct geometry (bottom).

Reducing Turnaround on Land
Three-dimensional surveys on land encounter many of the same difficulties as in transition zones, with the added problems of access, topography and extreme temperatures. All of these make for longer acquisition campaigns and more difficult processing. Under fair marine conditions, multielement acquisition can collect more than 75 km² [29 sq miles] per day. Under extreme land conditions, such as −40°C [−40°F] arctic surveys, acquisition may proceed at less than 1 km² [0.4 sq mile] per day. Land surveys of 1500 km² [586 sq miles] have taken up to 4½ years for acquisition. The potential for improvement in land 3D turnaround is undisputed.12

In land surveys more than other types, presurvey planning is the key to minimizing turnaround.13 Time spent planning and designing is more than compensated by time saved acquiring data. With a given set of equipment, say a certain number of geophones and people, one plan might achieve 150 to 200 shots a day, while a suboptimal plan with different shot and receiver line spacing may collect only 100 shots a day.

The most time-consuming tasks in acquisition—be they laying out receivers, drilling shot holes, repairing damaged cables or advancing to the next vibro location—must be identified and minimized to reduce turnaround. In the following examples of 3D land surveys in Texas, such bottlenecks were identified during presurvey planning and circumvented in novel ways.

Rough Terrain Turnaround
The Val Verde basin in Texas, USA is at the edge of the Sierra Madre mountains that extend north from Mexico (next page, bottom). The basin is a hot play for gas, with some wells in the region producing more than 7 MMcf/D. The terrain is extremely rough, with steep-edged mesas and incised canyons (next page, top). Several 3D surveys in the area have contributed to the continuous improvement of field operating procedures.

In one case, Conoco joined forces with Hunt Oil to acquire the Geaslin survey in the summer of 1994. Both companies had a short fuse: they had to evaluate their leases and make decisions for an early 1995 drill date. The survey design specified the number and location of shot points, but the short turnaround and high cost ruled out dynamite as a source, because too much time would be taken to drill shot holes. Vibro sources were available—four vibrating trucks at 12.5-m [41-ft] spacing constitute one source—but the terrain presented mind-boggling logistics: in some cases it would take four hours for a vibro trip up and down a mesa (next page, middle). The solution was to use two sets of buggy vibros, or eight in all, similar to a dual-source marine survey.14 While one set was shaking in the valley, the other set would work its way up a mesa. Similar dual-source vibro operations have been extremely successful in desert areas, such as Egypt and Oman, where there are no obstructions. In this case they allowed acquisition of 60 sq miles [153 km²] in 65 days.

As in all land jobs, darkness presents too many hazards, so the crew operates only during daylight hours. Evenings were well spent, though, running geometry verification on the day’s acquired data. One of the goals of the next shift was to have that day’s geometry checked and attached to the seismic traces, usually by midnight. That way, geometry problems could be fixed the next day, before the receivers were moved.


13. For a review of 3D seismic survey planning: Ashton CP; Bacon B; Mann A; Moldoveanu N; Déplanté C; Ireson D; Sinclair T and Redekop C: “3D Seismic Survey Design,” Oilfield Review 6, no. 2 (April 1994): 19-32.

14. Buggy vibros are vibros equipped with wider than normal tires. This allows access to rugged terrain while causing less damage to the environment.
Buggy vibrator source—vibro for short. Four such trucks shake in series to create a single source. Each vibro weighs 50,000 lbs [22,700 kg], is 30 ft [9 m] long and 10 ft [3 m] wide.

Rough terrain of Geaslin survey. The challenge of moving equipment on and off mesas was met by use of two sets of vibrator sources.

Location of 3D land surveys Val Verde County, Texas.
Processing the data from the Geaslin survey proved to be a great challenge. Val Verde basin is notorious for bad data. High-velocity carbonates near the surface deflect much of the source energy away from deeper layers; receiver and source coupling to the surface varies with location; and the rugged relief introduces high residual statics—differences in seismic travel time through surface topography. After four months of testing and processing, including 3D DMO and migration, the processing was complete. The next step is interpretation, in preparation for a possible 1995 drill date.

In the nearby Brown Bassett survey for Mobil, acquisition time was further shortened by the use of helicopters to move cables, recording boxes and geophones up and down the mesa and canyon walls. Three hundred “helibags”—net bags for transporting material—helped the crew complete the 60-sq mile [153-km²] acquisition in significantly less time than usual.

**What's Coming to Land**

Keeping track of all the information pertinent to a land survey is often the most time-consuming job, and steps are being taken to shorten it and make fuller use of all the information available. The Olympus-IMS information management system, now in use by Geco-Prakla in Germany, is designed to do just that.

The Olympus-IMS system colocates in a single database the many types of data that must be handled in a land survey. Previously, every type of data had its own database: the planned survey layout, the actual surveyed receiver and source point locations, shot hole drilling data, shooting schedule data and the recorded seismic trace data were handled by different software. The new integrated system minimizes the number of data handling steps, reducing errors and improving turnaround. The system will also link directly with processing software to allow field processing for geometry verification and further processing steps. The Olympus-IMS system will be available in Australia and Texas by the middle of 1995.

Further improvements in land turnaround will come from improvements in hardware and communication. In the most adverse conditions, a good crew may spend as little as two to three hours shooting out of ten spent in the field. In these circumstances, a small amount of time spent trouble-shooting equipment faults can have a considerable impact on turnaround. Geco-Prakla engineers are developing more reliable hardware, to reduce the amount of time spent looking for and repairing flaws in geophones, cables and connectors. Today, each receiver point marked on a map consists of up to 72 individual geophones, whose signals are combined to yield a less noisy signal at a central location, or source point (below). Up to 140,000 geophones will have to be repeatedly picked up, put down

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**Typical patterns for receiver and source arrays.** When geophysicists talk about a receiver or source position, they nearly always mean the central position of an array of receivers or sources. Arrays are designed to attenuate surface noise. Up to 72 receivers can be arrayed around the central position, and up to 20 individual source positions can be summed to make one source point.
and maintained in the course of a 3D survey. Efforts are also underway to find new ways to acquire the same amount and quality of data with fewer receivers, cutting survey time.

Improved communications will also cut turnaround time. Increased use of GPS is decreasing the time spent surveying positions for land source and receiver points. Surveying with GPS is faster and easier to check than traditional theodolitic surveying, and leaves less room for human error. Placing GPS units on vibro sources helps keep track of actual source locations and reduces location error.

For arctic land surveys, snow streamers have been developed in collaboration with Norsk Hydro as substitutes for hand-placed geophones in an effort to increase acquisition efficiency. Geco-Prakla engineers have tested snow streamers in six programs, acquiring 1200 km [750 miles] of 2D data. Efforts are also underway to minimize environmental impact, which in arctic environments must be included as part of turnaround—a single drop of oil spilled must be recovered before the crew moves.15

Connecting land crews via satellite to SINet, the Schlumberger Information Network, will give better day-to-day contact with office bases, speeding equipment and supply requests and allowing interaction with processing centers. The first such satellite link has been made in Venezuela, and others are planned.

Moving more processing to the field will further reduce turnaround for both land and transition zone surveys. Parameter testing, noise attenuation and velocity picking can be done with today's field processing tools. But full concurrent processing, as performed in marine surveys, is still a dream for land. Land acquisition, more so than marine, is a three-dimensional problem: sources are not aligned with receiver lines, and more time is needed to acquire enough seismic traces to process one part of the 3D volume. At best, processing through to stacking could lag acquisition by a few weeks, but the difficult task of computing residual statics before stacking cannot begin until all the data are in. Advances may come from taking a new view of 3D land surveys—planning, acquiring and processing with a truly three-dimensional view—rather than simply repeating a series of two-dimensional snapshots.

### The Role of Integrated Services in Reducing Turnaround

Marine, TZ and land 3D surveys are sure to find further turnaround improvement in the common ground of integrated services. In an integrated-service survey, planning, acquisition, processing and project management are delivered by one service company. Traditionally, the oil company plans the survey, then one contractor acquires the data and another processes it. Time is wasted transferring data and responsibility between parties.

Geco-Prakla has developed an integrated service for 3D surveys called TQ3D—Total Quality 3D. Larger in area than most surveys, TQ3D projects can cover leased and open blocks. A TQ3D project may be operated from 100% proprietary to 100% nonexclusive, or anywhere in between. Data acquired on a proprietary basis become the property of the operator. Large projects can involve several operators. Data acquired on a nonexclusive basis become the property of Geco-Prakla, and may be licensed.

The turnaround improvement achievable through integrated services is remarkable. A mixed proprietary-nonexclusive TQ3D for BP in UK block 47/10 was started and completed in November 1994. Geco Topaz acquired the 230-km² [89-sq mile] survey in three weeks. While full-fold data were being acquired, a 20-fold data volume was partially migrated onboard, and processing was completed onshore. Processed data were sent to the GeoQuest Data Services group via SINet, and converted to Charisma workstation format. Total project time was four weeks. Thirty-four such marine surveys have been completed, and 21 more are in progress, covering a total of 43,000 km² [16,800 sq miles].

Integrated services are also reducing land survey turnaround. Land surveys, with their difficult logistics, benefit from the approach a committed team brings to a project. In addition to survey design, acquisition and processing, land surveys require obtaining permission to access an area from those who own and live on the land. The project can run more smoothly when a single contractor coordinates every phase. One such project in Africa turned around a 50-km² [20-sq mile] survey in seven months, from planning through installation of processed data onto an interpretation workstation. Two other projects are in the survey design stage.

In recent years, there has been a small revolution in our ability to evaluate carbonates. Novel technology and a community of interpreters determined to crack one hard nut are forcing carbonate reservoirs to reveal many of their secrets.

Carbonate reservoirs account for 40% of today's hydrocarbon production, and because of several elephant fields in the Middle East they are expected to dominate production through the next century. Therefore, understanding carbonate reservoirs and producing them efficiently have become industry priorities and are likely to remain so.

Current efforts in carbonate exploitation focus on correctly targeting new wells, frequently horizontal, to optimize production from untouched reserves and on ensuring that massive water injection schemes deliver an effective sweep of the reservoir. In support of these efforts, geoscientists are trying to decipher the enigma of carbonate rock's complex pore space and understand how permeability barriers and conduits affect reservoir behavior. This article tracks the interpretation process, from carbonate rock description and petrophysical log evaluation to new techniques for measuring permeability downhole and mapping large-scale flow conduits and barriers.

**Carbonates for Beginners**

Carbonates and sand-shale rocks, or siliciclastics, are worlds apart. Whereas siliciclastic rocks are composed of a variety of silica-based grains that may have traveled hundreds of miles from their source, carbonate rocks mainly consist of just two minerals—calcite and dolomite—and remain near their point of origin. Carbonates form in shallow and deep marine settings, evaporitic basins, lakes and windy deserts. Most of the carbonates formed in past have shallow...

Unfilled interparticle porosity (black). Holocene oolite, Great Salt Lake, Utah, USA. Cross-polarized light photograph.

1. An exception is the less-abundant class of rocks called calcareous sandstones, or carbonate arenites, which form when carbonate rock is broken up by wind or water, then transported and deposited. Calcareous sandstones exhibit many of the structural and petrophysical characteristics of siliciclastic sandstones, while retaining carbonate mineralogy and microporosity.

2. For a review of carbonate geology:

The typical carbonate rock is made of grains, matrix and cement. Grains are either skeletal fragments of small organisms or particles precipitated from calcium-rich water. The latter includes a variety of small, accretionary grains identified according to their size, origin and internal structure.

Matrix is the lithified mud of deposition that fills most of the space not occupied by grains. In carbonates, fine mud has several sources—chemical precipitation, breaking of skeletal material into finer material,
remains of algae, and others. On lithification, mud becomes a very fine-grained calcite called micrite.

Cement describes crystalline material that forms in most of the space remaining between grains and matrix or between grains themselves, binding them. Cement may have a variety of crystal sizes depending on its composition, the conditions of crystallization and the spaces to be filled.

Crucial to the interpretation of carbonates is classifying the numerous ways grains and matrix coexist. Progress in categorizing these complexities surged in the late 1950s because of pressure within oil companies to better understand their carbonate assets. The classification that has stood the test of time most successfully is by Robert Dunham.4

Dunham classifies a spectrum of rock types based on the internal structure and texture of the rock (below). Mudstone consists mainly of matrix in which relatively few grains are suspended. Wackestone is also matrix-supported but has more grains. Packstone has enough grains for them to start providing support—matrix fills the remaining nonpore space. Grainstone has plenty of grains providing support and includes progressively less matrix. Finally, boundstone describes carbonate rocks in which the original material provided support during deposition, such as in reefs. Crystalline describes rock that has lost its depositional fabric because of diagenetic recrystallization, for example, dolomitization.

Dunham’s classification provides some clue to the energy of deposition. The mud-based mudstone and wackestone are deposited in low-energy settings. Packstone and grainstone would appear to be from high-energy deposition, but given significant diagenesis, these grain-supported rocks could equally well have been deposited as mud-supported agglomerations and then through compaction and chemical alteration transformed to their present state. The difficulty in classifying carbonates to reflect both their current state and depositional history demonstrates how dominant diagenesis is in forming the final carbonate rock.

Diagenesis may be divided into five main mechanisms: compaction—the reduction of pore space in response to tighter grain packing as overburden increases; carbonate degradation—the destruction of carbonate material through chemical dissolution and micritization, the transformation of large crystals into small ones; carbonate aggradation—the construction of carbonate material through precipitation of cement between grains, and recrystallization, such as the replacement of limestone by dolomite; stylolitization—the formation of stylolites, irregular planes of discontinuity between rock units due to compaction-related pressure solution; and fracturing—the planar breaking up of rock mass due to stress.

Time and diagenesis generally work against the preservation of porosity (next page). Young carbonates usually have porosities around 60%. Old carbonates have just a percent or two. Reservoir carbonates survive with porosities of 5 to 15% largely because the presence of hydrocarbon impedes further destruction of porosity. The typically prolonged and extensive diagenesis in carbonates also usually obscures the provenance and history of the rock.

Reservoir Description
How does the reservoir geologist use these descriptions to help plan the optimum exploitation of a carbonate reservoir? Identifying and classifying carbonates are crucial in two key tasks. First, assessment of the reservoir’s paleoenvironment builds a broad understanding of likely reservoir geometry. Then, detailed well-to-well correlation of lithofacies helps construct a detailed threedimensional picture.

Clues to paleoenvironment come from every available source—seismic surveys, outcrop studies, cuttings and core analysis, and logs, including those from the latest generation of electrical imaging tools, which can capture the wellbore likeness to a resolution of about 5 mm [0.19 in.] The main paleoenvironment indicators are:

- **Lithology**—This provides a general idea of the depositional setting. The presence of clastic rocks indicates an external source of sediment, while their absence indicates an environment free of external influence.

- **Rock texture**—The Dunham classification of texture provides some idea of the energy of deposition. Grain size variations also point to the sequence of deposition. For example, a fining upward sequence may indicate a relative sea level rise, or marine transgression. A coarsening upward sequence probably indicates a relative sea level drop.

- **Sedimentary structure**—Large-scale sedimentary structures are more difficult to see in carbonates than in siliciclastics, but when identified, they offer powerful clues to the depositional environment. Examples are crossbeds in eolian dunes or solu-
Creation and destruction of carbonate porosity due to compaction and diagenesis, as a function of age. Inset—Transformation of a shell to create various molds and casts, as it undergoes different combinations of burial, filling and dissolution. (Adapted from Reeckmann and Friedman, reference 2.)

Subhorizontal stylolites (wide dark bands) and inclined fractures (narrow dark lines) in a Middle East carbonate formation.

Swarms of stylolites in a Mississippian carbonate, with two core points visible.

Mottled fabric with thin producing zone at XX88 ft. Dark color is interpreted as mud-filled porosity. Light color is grains and matrix.

With water-base mud is the FMI Fullbore Formation MicroImager tool, which provides a picture of most of the borehole with 192 small current-emitting buttons mounted on four pads and four flaps. In the images, light color denotes high resistivity, indicating rock grains or hydrocarbon-filled pores, and dark color indicates low resistivity such as water-filled pores or shale. The images are no substitute for core analysis, but rather a complement to them. Other evidence is frequently needed to corroborate an interpretation, for example to decide whether a dark patch is porosity or shale. However, an experienced interpreter of FMI images can glean strong evidence of numerous types of carbonate features down to the centimeter scale (this page and next page).

A recent trend in FMI interpretation has been toward quantitative analysis of the images. One processing method automatically extracts five facies types based on a textural classification by Nurmi et al. The facies are uniform zones of constant conductivity or resistivity; layered zones of alternating conductive and resistive layers; zones

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Unconformity between overlying shale and mid-Cretaceous carbonate. Large, irregular dark features below the unconformity are voids created by extensive dissolution during subaerial exposure.

Breccia caused by collapse of a limestone cavern, indicated by interconnected channels between sharp fragments of rock. This type of breccia porosity often makes for prolific production.

Secondary micrite formation in the form of large, light-colored areas.

Large calcite concretion, that may help elucidate depositional environment.

Mottled fabric of an Upper Cretaceous carbonate reservoir in the Middle East.
with interwoven or contiguous conductive areas, interpreted as interconnected porosity; resistive zones with isolated conductive areas, interpreted as nonconnected pores; and conductive zones with isolated resistive areas, caused for example by nonconducting calcite or anhydrite nodules. Such a zonation can be rapidly calculated from the images and lends itself readily to facies mapping across a field (below).

A more advanced processing method actually delineates identifiable objects such as rock grains or pores on the images. This is quite a challenge because picking the edge of an object depends somewhat on overall image intensity, which varies. The solution is to equate object boundaries with inflection points in image intensity. This approach is incorporated in SPOT—Secondary Porosity Typing—prototype software running on Geo-Quest’s GeoFrame platform. Current SPOT processing can yield the boundaries of both resistive (light color) and conductive (dark color) features (next page, top). In tests made on laboratory rock samples bored with “pores” of varying but precisely known diameter, the processing has given accurate and consistent pore delineation.

Once resistive and conductive features are delineated, then all manner of quantitative information can be computed, such as their average size, the spatial density of the features, the total area on the image covered by the features, and the degree to which like features are connected. We will later address how these new parameters may contribute to understanding of rock porosity and permeability.

The average sizes of resistive and conductive features have recently been used to help identify Dunham rock types in an Occidental Oil Company field in Indonesia and thus contribute to facies mapping (page 46, bottom). In this interpretation, resistive features correspond to carbonate coral framework or grains, while conductive features correspond to pores or micritic matrix. On a log, the average sizes of the two types of features are played back together. The interpretation proceeds by noting the separation between the curves and also their absolute magnitudes.

Mudstone is interpreted when separation is at a maximum. This occurs when the average size of conductive features peaks—that is, micritic cement dominates—and the average size of resistive features—or grains—drops. Wackestone is interpreted when the average size of resistive features increases, while the average size of conductive features remains about the same. Packstone is interpreted when the average size of resistive features peaks. And finally, grainstone is interpreted when the sizes of conductive and resistive features become equal. This broad-brush methodology has been verified against macrofacies descriptions from cores in two wells in the field. Furthermore, the frequency with which the two curves mirror one another appears to indicate the frequency of a complete depositional cycle—from low-energy mudstone to high-energy grainstone.

Nurmi's porosity classification through automatic processing. The FMI image is processed to yield resistive and conductive segments (B). Segments that are not continuous across the image are eliminated (C). Conductive area within each processed image is plotted as a log (blue for B, red for C). Average conductivity for resistive segments in B (green) and for conductive segments in B (orange) are shown with the variation in thickness of these segments across the image width (black).

SPOT processing on FMI images delineates either resistive or conductive inclusions, or spots. The inclusions can then be analyzed to provide quantitative parameters such as median size of inclusion, density of inclusions per foot or meter, average area percentage of inclusions, and even a porosity estimate and connectivity parameter.

Cross-polarized light photographs showing porosity. Left: Reduced interparticle and intraparticle porosity (black) in foraminifera and mollusks. Pleistocene Key Largo Limestone, Florida, USA. Middle: Intercrystal porosity (black) in a fine- to medium-crystalline replacement dolomite. Middle Eocene Avon Park Limestone, Florida. Right: Moldic porosity (black). Pleistocene Miami oolite, Florida.
Without images, mapping facies following gamma ray and other log signatures can often prove unreliable. The safest bet, short of coring every borehole, is to collectively interpret all available log data, initially calibrating the interpretation results to core data. An example of this approach can be found in a study by the Indian Oil and Natural Gas Commission (ONGC) and Schlumberger that recently addressed a complex Middle Eocene carbonate formation in offshore India.9

In this study, the first step was to identify facies in the four cored wells according to Dunham’s classification. This required the analysis of 120 thin sections, 12 polished sections and 6 scanning electron microscope images. This petrologic interpretation was then integrated statistically with five log measurements made in the same wells—density, neutron porosity, sonic travel time, gamma ray and saturation. Matching the log measurements to the facies descriptions revealed clear links between weighted combinations of log data and the Dunham classification (above, left). However, rather than Dunham’s four, the logs recognized five facies types, the last of which always occurred within a wackestone zone but at depths where no core was retrieved. This facies was termed wackestone+. With logs calibrated to a core facies description, a facies interpretation could be made directly from logs in all the remaining uncored wells, and then facies mapped between wells.

Petrophysical Evaluation

Facies determination from logs is hard enough, but the challenge of establishing petrophysical parameters such as saturation and permeability is even more daunting. The reason lies squarely with the complex diagenesis and resulting convoluted pore systems of most carbonate rocks. Log analysts divide porosity into primary and secondary components, with primary existing at the time of rock formation and secondary appearing as the rock matures and diagenesis prevails. The more detailed classification of Choquette and Pray exposes the immense diversity in both shape and size of carbonate pores (next page, top).10

The variety in pore type explains why permeability answers remain so elusive. Vugs and their cousins may make for high porosity, but a consistent pore connectivity, usually taken for granted in sandstones, may or may not be present. Worse yet, the chaos

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**Facies interpretation according to Dunham’s classification using statistical calibration between log data and petrologic analysis from cores in an offshore carbonate field, India. The calibration allows facies to be mapped across the field using other logged wells without cores.**

**Facies interpretation in an Occidental Oil Company carbonate field in Indonesia using SPOT processing to automate Dunham’s classification from FMI images. Dunham rock type is interpreted by comparing the relative magnitudes of the average size of resistive and conductive inclusions. Interpretation has been verified from cores.**
reigns at all scales. In sandstones, small 1/2-in. [1.27-cm] plugs bored from cores usually provide samples homogeneous enough for estimating average permeability. In carbonates, however, sometimes not even a whole piece of core can be regarded as representative. The discrepancy between permeabilities measured at different scales may be related to heterogeneity or to anisotropy. The only sure way of estimating reservoir-scale permeability is by using wireline, drillstem or production tests. This was the approach taken in the second phase of the Indian study, in which nine well tests in two wells established a link between carbonate facies type and permeability.

Each carbonate facies type was allowed a permeability value, to be determined. Then, for each test, the well’s flow capacity calculated during the test was matched with the sum of the individual flow capacities of the well’s various facies types. Each facies’ flow capacity was the product of the facies type’s unknown permeability and its cumulative thickness in the well. The result of the match was a range of permeabilities for each facies type, two types—grainstone and wackestone+—being particularly permeable. Production logs in one well confirmed the productivity of wackestone+ (right).

A much earlier study, predating imaging technology, also recognized clear differences in permeabilities of the rock types of the Dunham classification. This study first

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### Fabric-selective vs. Not fabric-selective vs. Fabric-selective or not

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<td>Shrinkage</td>
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<tr>
<td>Growth-framework</td>
<td></td>
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</tbody>
</table>

*Cavern applies to man-sized or larger pores of channel or vug shapes

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Matching well tests with Dunham-style evaluation in an Indian offshore carbonate field to provide permeability values for main facies types. Cumulative flow profile (left) and flow contribution from each layer (middle) confirm high permeability of wackestones (right).

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used a rudimentary log interpretation method to distinguish one rock type from another (below, left). Once the type was identified, a relevant porosity-permeability relationship was applied at each depth to calculate permeability from porosity logs. The procedure resulted in far better agreement with core permeability measurements than had previously been obtained.

In general, there are two ways to establish elusive petrophysical parameters such as permeability from log data. One is to link the parameter statistically to log data, calibrating the link with measurements of the parameter made in the field or laboratory. The calibration can be in just one well or an entire field. An example is the Indian offshore study where well test results were linked to a statistically derived facies interpretation. The variety of such statistical methods is immense and currently extends to the use of neural networks that attempt to mimic and even improve on our inherent ability to recognize patterns in diverse data.

The other approach is to somehow directly measure something about the rock's pore space, ideally from logs, and then tie this in with sought-after petrophysical parameters such as saturation and permeability. To this end, the newest measure comes from FMI images, again thanks to SPOT processing. The proportion of an image delineated as pore space leads directly to a new estimate of porosity, subject of course to the interpretation that dark areas of the image are indeed pores.

In a well drilled through a carbonate reservoir in Italy, SPOT-derived porosity compares well with porosity conventionally interpreted from neutron and density logs (below, right).

In much of the logged interval, the two porosities agree well, while elsewhere porosity derived from the FMI images is substantially less than conventional porosity. This could be due to the FMI tool responding only to pores larger than the 5-mm resolution of the tool and missing smaller intergranular and micritic pores. Interestingly, zones where the two porosities differ coincide with zones flagged with a secondary porosity index by the SPOT interpretation.

Another SPOT calculation is connectivity, an elaborately conceived but necessarily limited attempt to quantify the degree of connection between pores identified on images. A limitation is imposed because two-dimensional images can say only so much about three-dimensional connectivity. Nevertheless, SPOT connectivity has successfully predicted the productivity of oil
and gas wells in Texan and Oklahoman Ordovician carbonates with vuggy, connected porosity (above).

Without images, the commonest approach to pore geometry lies through consideration of Archie’s law with its cementation exponent $m$:

$$R_e = \frac{R_w}{\phi^m},$$

in which $R_e$, $R_w$, and $\phi$ are, respectively, the water-filled formation resistivity, connate water resistivity and porosity. Early on, researchers realized that the cementation exponent captured something about the pore space, particularly its tortuosity, and thus could serve to estimate permeability as well as interpret resistivity logs. Several theoretical expressions for permeability based on $m$ have been developed, this being a recent example:

$$k = 126.7 \phi^m R^2 \text{ millidarcies},$$

in which $R$ is an “effective” pore radius in microns.

The exponent $m$ measures reasonably constant at about 2 for sandstones, as it does for similarly constructed oolitic carbonates. But otherwise in carbonate rock, it wanders all over. In fractured carbonate rock $m$ tends to 1, and in rocks with nonconnecting vugs $m$ rises to 3, 4 or higher (below, left). A particularly copious study on Qatar carbonates by Focke and Munn shows not only how $m$ varies with porosity—it varies a great deal—but also how that functionality depends on permeability. The challenge in using $m$ to evaluate a carbonate therefore depends on being able to reliably estimate the exponent at any depth, rather than use an arbitrary value, generally 2, derived from observations on sandstones.

Guidelines for achieving this were first offered by Lucia of Shell Oil in 1981. Using samples from carbonate reservoirs in Texas, USA and Alberta, Canada, Lucia noted that $m$ depended unambiguously on the proportion of the rock’s porosity coming from unconnected vugs. Estimate that from core samples, he suggested, and a likely $m$ could be derived for selected intervals in the well.

But a more versatile method was soon devised that permitted estimating $m$ foot by foot. This made use of a new logging measurement—high-frequency electromagnetic propagation travel time, or $t_{pl}$. Like the resistivity log, $t_{pl}$ responds to water-filled porosity, but does so without an exponent. Combining resistivity and $t_{pl}$ therefore allows elimination of porosity for a continuous evaluation of $m$. The results of such an $m$ computation transformed the accuracy of carbonate evaluation in a number of Middle East fields (next page, top). The methodology was later extended to take advantage of yet another wireline measurement, the TDT Thermal Decay Time log, permitting the continuous evaluation of not just $m$, but also the saturation exponent $n$.

The exponent $n$ appears in Archie’s law

$$R_e = \left(\frac{R_w}{\phi^m S_n^2}\right)^{1/n}$$

adapted for hydrocarbon-bearing rock:
in which $S_w$ is water saturation. Like the exponent $m$, $n$ also runs into trouble in carbonates, sometimes varying dramatically from the conventionally assumed value of 2.21 This has been shown in several sets of experiments on cores, the most recent by Bouvier (below).22 Petrophysicists suspect the likely cause of discrepancy is tiny micropores in the micritic matrix. Most probably, these small pores still contain original water while the large pores contain oil. It is also probable that the micrite remains water wet, while the grains have become oil wet. Both phenomena would explain why carbonate formations producing only oil sometimes exhibit low resistivities more characteristic of a water-bearing formation. Essentially, the water-filled micropores provide a short-circuit to the survey current.

In summary, the classic Archie approach for analyzing the complex pore geometries of carbonate is fraught with obstacles, which have been only partially overcome.

**New Logging Techniques**

Today, two new techniques—nuclear magnetic resonance (NMR) logging and Stoneley wave logging—offer new perspectives on carbonate permeability and pore structure. The theoretical foundations for both techniques have been known for years, but until recently neither has received adequate technical implementation. That is changing with the introduction of the CMR Combnable Magnetic Resonance tool and the DSI Dipole Shear Sonic Imager tool.

In nuclear magnetic resonance, sharp magnetic pulses are used to momentarily reorient hydrogen molecules away from the ambient magnetic field direction. After each pulse subsides, the hydrogen molecules realign themselves with the ambient field, oscillating about it as they do so. Observing these oscillations permits measuring how many hydrogen molecules relax after the imposed magnetic pulse and also the rate at which they realign to the ambient field, called the relaxation.

The implications for logging are dramatic. The measurement of how many hydrogen molecules relax provides a measure of porosity, and the relaxation times indicate the size of pores containing the hydrogen molecules. Relaxation times are short in small pores because the hydrogen molecules are near the grain surface where interaction with surface charges speeds relaxation. Relaxation times are longer in large pores. Measuring the spectrum of relaxation times—so-called $T_2$ relaxation...
the formation. This rules out the possibility of a borehole signal, a problem that plagued earlier technology that used instead the much weaker and unfocused earth's field. Eliminating the borehole signal used to require the expensive and unpopular technique of doping the entire mud column with magnetite. The new tool's depth of investigation is about 1 in. [2.5 cm], and a dead zone directly in front of the pad avoids most effects from mudcake or rugosity. Vertical resolution is just 6 in. [15 cm], facilitating comparisons with the high-resolution FMI logs.

Recent CMR logs run in carbonate formations in West Texas coupled with laboratory measurements on cores from the wells illustrate exciting possibilities for overall petrophysical evaluation.24 The formations in question are partly dolomitized carbonates with a good deal of nonconnected vuggy porosity. In addition, silt layers create vertical permeability barriers. The main interpretation challenge is to estimate at any depth what percentage of porosity actually contributes to production. This requires being able to discount the minute pore space in the silt and also any vuggy porosity that is not connected.

T2 spectra were measured on water-saturated cores both before and after they had been centrifuged to expel all producible water (below). Before centrifuging, the spectra show water-filled porosity covering the full range of pore sizes, while spectra after centrifuging no longer show the large pore sizes, since the water has been expelled from them. Equating the porosity difference between the two spectra with the volume of water expelled during centrifuging established a T2 cutoff of 95 msec to divide large from small pores. Applying this cutoff to spectra measured by the CMR tool provided an estimate of small-pore porosity that correlated well with silt intrusions evaluated times—resulting from each pulse promises to give an indication of the range of pore sizes in reservoir rock. In sandstones, comparisons between T2 relaxation times and mercury porosimetry, a standard lab technique for evaluating pore sizes—pore neck sizes to be precise—are generally good (above).23 This indicates that in sandstones, there is a predictable relationship between pore and pore neck sizes. Researchers are conducting similar measurements on carbonates, but results so far have not shown the same predictable relationship.

The CMR measurement is made from a pad-type tool with permanent magnets that provide an ambient field focused entirely into

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from other logs. Following visual analysis of the cores, a second cutoff at 750 msec was selected to isolate vugs from intergranular porosity. This was also applied to spectra measured downhole, providing a log of vuggy porosity (below).

Recent laboratory work on core samples from the carbonate Mubarraz field in Abu Dhabi, UAE, confirms the potential of NMR measurements.25 A challenge in this area is to distinguish small micropores in the micrite matrix from the much larger productive intergranular pores. Analyzing 20 samples from two wells, a team of Schlumberger and Abu Dhabi Oil Company geoscientists found that micropores were correctly identified using a relaxation time cutoff of 190 msec on laboratory-measured \( T_2 \) spectra. Furthermore, permeable grainstone facies could be distinguished from lower-permeability packstones and mudstones with a cutoff of 225 msec. Finally, the NMR data could be interpreted to give more accurate permeability estimates than those obtained from conventional porosity logs. The CMR logging tool is currently being tested in Abu Dhabi, and expectations are high that similarly impressive results will be obtained in boreholes.

Another logging tool, the DSI imager, gains direct entry to permeability by physically moving fluid through the formation. This is achieved when low-frequency tube waves—called Stoneley waves—propagate up and down the borehole. The Stoneley wave preserves most of its energy in the borehole, but in permeable formations some energy is attenuated when wave pressure pushes fluid from the borehole into the formation, similar to a quick, small-scale well test. This slows the velocity of the wave by an amount that can be related to the ratio of formation permeability to fluid viscosity. Given a viscosity for the borehole fluid, in well-controlled circumstances such as laboratory measurements or boreholes with no mudcake, the permeability can then be estimated.26

The DSI tool generates Stoneley waves with a special monopole transmitter at frequencies of 600 Hz to 5 kHz, ideal for tube-wave logging and a quantum leap ahead of previous technology equipped with transmitters operating in the 10 to 20 kHz range. Recent estimation of permeability using Stoneley-wave velocity as obtained from the DSI tool shows impressive agreement with core permeability measurements in an Abu Dhabi carbonate reservoir (next page, top right).27

The method of obtaining permeability using Stoneley-wave velocity requires knowing the formation’s density and shear velocity. A second method establishes permeability from the Stoneley wave without other data. This method is based on observing how permeability attenuates Stoneley-wave energy by directly comparing signals from near and far receivers.28 Attenuation is


greater at higher frequencies, so the comparison is more sensitive if measured at the high end of the Stoneley-wave frequency spectrum. Excellent agreement has been observed in Middle East carbonate reservoirs between permeability estimates obtained using this second method and production logs and core data (bottom).

Research continues into improving Stoneley-wave permeability, for example in

**Filled fenestral porosity in a blue-green algal biolithite. Porosity may be due to air spaces in crinkled mat sediments. Upper Silurian Limestone, Pennsylvania, USA.**

Permeability estimated from Stoneley-wave attenuation without recourse to other log data, compared with permeability from Stoneley-wave velocity, in a Middle East carbonate reservoir. Integrated permeability shows an excellent match with a flowmeter production log.
accounting for the presence of mudcake, which almost certainly interferes with the tube wave’s ability to move formation fluids. **Large-Scale Features**

Mapping reservoirs at the large scale and understanding their complex petrophysics at the small scale are all part of the challenge facing reservoir geologists and engineers. But in carbonates, additional care must be taken to recognize and evaluate two types of medium- to large-scale features that are caused by overburden and tectonic stresses. Either can dramatically affect reservoir performance, creating heterogeneous or anisotropic behavior where none might otherwise be suspected. These two features are stylolites and fractures.29

Stylolites occur in any sedimentary formation, but are particularly common in carbonates—picture the thin, sawtooth “veins” visible on polished marble tiles and floors. Stylolites are easily recognized on outcrops and cores as irregular planes of discontinuity between rock units. Formed during compaction, probably through the mechanism of pressure solution, stylolites concentrate fine-grained insoluble residue along their irregular seams. They are usually assumed to act as permeability barriers, but some core measurement results confirm that stylolites can develop permeability. Identifying them and evaluating their impact on permeability are therefore top priorities for the reservoir engineer.

Borehole imaging has greatly facilitated the identification of stylolites downhole (right and next page). Viewed with the FMI

Filled shelter porosity beneath a large mollusk fragment. Pliocene and Pleistocene Marl, Florida.

Three types of stylolites identifiable on FMI images. Dark colored stylolites (left), probably filled with clay; stylolites associated with a light band (below), are probably resistive calcite. Some stylolites are associated with extensional fractures (next page, left).
tool, they appear in three common varieties. First, some stylolites exhibit undulating but slightly irregular surfaces and are filled with dark, therefore conductive material, probably clay. A second group of stylolites seems to have an associated band of light color, most likely resistive calcite. The third type of stylolite clearly shows associated extensional fractures caused by excessive overburden stress.

The question remains: Which stylolites form permeability barriers and which do not? Until recently, there has been no sure way of deciding. Now, answers are obtainable from a third-generation wireline testing tool, the MDT Modular Formation Dynamics Tester tool. Unlike previous wireline testers, this tool permits testing between probes set as far apart as 8 ft [2.4 m], a large enough interval to comfortably straddle a stylolite. In such tests recently performed in the Middle East, MDT measurements indicated that stylolites previously assumed to be completely impermeable may in fact be partly conductive to fluid flow.

If stylolites generally impede flow, fractures almost always enhance it. Indeed, some reservoirs, particularly carbonate ones, rely exclusively on fractures to achieve commercial levels of production. Before the advent of wireline imaging techniques, detecting fractures was difficult and characterizing anything about them was almost impossible. That bleak outlook changed dramatically with the introduction of the FMI and DSI tools. The recently introduced ARI Azimuthal Resistivity Imager tool also makes an important contribution in fracture detection.

Briefly, all three tools contribute to fracture interpretation, but each alone may not provide a complete picture. On FMI images, open fractures filled with invading water-base mud of high conductivity are recognizable as dark and usually fragmented sinusoid traces. With the help of interactive FracView image processing, the interpreter can reliably pinpoint fractures, calculate their dip and azimuth, and estimate spatial density at the borehole. Additional analysis of image resistivity near the fracture can also lead to an estimation of fracture aperture.

With simple models of fracture geometry, the combined log information may provide an effective fracture permeability. This can then be integrated with permeability estimates for the unfractured part of the rock to yield a permeability for the whole rock. In

The reduced fracture porosity (black) of the Upper Jurassic Limestone, Germany. Cross-polarized light photograph.

Reference:
the Rocky Mountains, where a low-porosity carbonate reservoir depends on fractures for production, such a combined permeability has been successfully compared to permeability obtained from drill-stem tests (left).

There are a few caveats, however, to fracture interpretation using FMI resistivity images. First, the calculated fracture aperture seems to be influenced by the fluid originally filling the fracture—fractures in water zones appear systematically wider than nearby fractures in hydrocarbon zones. It is suspected that invasion fails to remove all hydrocarbon from the walls of the fracture, thereby making the fracture look thinner to electrical imaging techniques.32 In a depleted carbonate field being exploited for additional oil using horizontal wells, this phenomenon has been put to good use in identifying fractures that are likely to allow water breakthrough (next page).

Second, the FMI tool is a relatively shallow measurement, and this limits the tool’s ability to distinguish natural fractures that contribute to reservoir performance from drilling-induced fractures that do not. Certain types of drilling-induced fractures are easily recognized by their geometry—for example, vertical fractures oriented perpendicular to the least horizontal stress and therefore intersecting a vertical borehole over a lengthy interval. Nonvertical drilling-induced fractures, however, are harder to distinguish and may be easily confused with the natural variety. Fracture identification in highly deviated and horizontal wells becomes harder still.

The ARI tool provides some added depth of investigation but a poorer along-borehole resolution, and as a result, fewer fractures are detected. However, ARI image processing provides some clue to fracture depth as well as aperture, although neither is unambiguously determined.33 The two parameters are genetically linked, so the tool response to a fracture enables an estimate of one of the parameters once a value for the other is taken.

Greater depth of investigation, up to several meters, is provided by the DSI tool that detects open fractures in the same way that it senses a permeable formation—by employing the Stoneley wave to physically pulse mud into and out of the fracture.34 However, there is a commensurate deterioration in resolution along the borehole axis, to about 1.5 m [4.9 ft], showing closely spaced fractures as a single fracture. Like the FMI measurement, the Stoneley wave permits the evaluation of fracture aperture, though again this may actually represent the
cumulative apertures of several neighboring fractures. Comparisons between fracture aperture estimated from the two techniques have shown good agreement in metamorphic volcanics at a UK waste disposal site. On the down side, the Stoneley wave yields no information on fracture dip or azimuth.

There may be further to go in fracture interpretation, but a comparison between the techniques of ten years ago and those of today reveals the extraordinary advances achieved by novel wireline technology and a spirited community of interpreters. It is a level of improvement common to all areas of carbonate interpretation. Today's exploitation in increasingly complex and difficult reservoirs has gained from a veritable revolution in formation evaluation. Long may it continue.

—HE, LS

