It is hard to believe that logging while drilling (LWD) has come such a long way over the last decade. In the early 1980s, LWD measurements were restricted to simple resistivity curves and gamma ray logs, used more for correlation than formation evaluation. Gradually, sophisticated resistivity, density and neutron porosity tools have been added to the LWD arsenal.1 With the advent of high-deviation, horizontal and now slim multilateral wells, LWD measurements often provide the only means of evaluating reservoirs. The quality and diversity of LWD tools have continued to develop quickly to meet this demand. Today, applications include not only petrophysical analysis, but also geosteering and geological interpretation from LWD imaging (next page).2 This article focuses on the latest LWD resistivity tools—the RAB Resistivity-at-the-Bit tool and the ARC5 Array Resistivity Compensated tool—and the images they produce (see “A Profile of Invasion,” page 17).

For help in preparation of this article, thanks to Samantha Duggan, Anadrill, Sugar Land, Texas; Tom Fett, Geo-Quest, Houston, Texas and Mary Ellen Banks and Martin Lüling, Schlumberger-Doll Research, Ridgefield, Connecticut.
Formation evaluation made by combining data from several LWD measurements. This log interpretation was made using ELAN Elemental Log Analysis software and data from the RAB Resistivity-at-the-Bit tool, CDR Compensated Dual Resistivity and CDN Compensated Density Neutron tools.

Volumetric analysis (track 5) shows a quartz-rich zone of relatively high porosity. The brown shading indicates the movable gas volume calculated from CDR and RAB data run several days later. The RAB resistivity image (track 4) shows that the sand body is split into three main lobes with shale permeability barriers.
Geology From the Bit

Simply stated, resistivity tools fall into two categories: laterolog tools that are suitable for logging in conductive muds, highly resistive formations and resistive invasion; and induction tools which work best in highly conductive formations and can operate in conductive or nonconductive muds. The RAB tool falls into the first category although, strictly speaking, it is an electro-resistivity tool of which laterologs are one type (see “From Short Normal to Axial Current,” page 9).

The RAB tool has four main features:
- toroidal transmitters that generate axial current—a technique highly suited to LWD resistivity tools;
- cylindrical focusing that compensates for characteristic overshoots in resistivity readings at bed boundaries, allowing accurate true resistivity \( R_t \) determination and excellent axial resolution;
- bit resistivity that provides the earliest indication of reservoir penetration or arrival at a casing or coring point—also known as geostopping;
- azimuthal electrodes that produce a borehole image during rotary drilling.

This last feature allows the RAB tool to be used for geological interpretation.

Three 1-in. [2.54-cm] diameter buttons are mounted along the axis on one side of the RAB tool. Each button monitors radial current flow into the formation. As the drill-string turns, these buttons scan the borehole wall, producing 56 resistivity measurements per rotation from each button. The data are processed and stored downhole for later retrieval when the RAB tool is returned to the surface during a bit change. Once downloaded to the wellsites workstation, images can be produced and interpreted using standard geological applications like

3. It should be remembered that laterolog and induction tools both work well in many environments. Laterolog tools need a complete electric circuit to work. Current passes from an emitting electrode through the borehole into the formation and back to the tool via a surface electrode or a return electrode on the tool. Resistivity is a function of voltage drop, between return electrode and source, and source current. Laterolog tools must have an electric contact with the formation through either a conductive mud system or by direct physical contact. They are capable of logging highly resistive formations and are good at spotting thin resistive beds.


6. Coiled tubing, run into a borehole, forms a natural helix. At some stage the frictional forces between borehole and coiled tubing become greater than the force pushing the tubing downhole causing the helix to expand and lock tight against the borehole wall—helical lockup.
Wellsite images allow geologists to quickly confirm the structural position of the well during drilling, permitting any necessary directional changes. Fracture identification helps optimize well direction for maximum production.

Finding the Cracks in Master’s Creek
Murray A-1 is a dual-lateral well drilled by OXY USA Inc. in the Cretaceous Austin Chalk formation, located in the Master’s Creek field, Rapides Parish, Louisiana, USA (top right). The Austin Chalk is a low-permeability formation that produces hydrocarbons from fractures, when present. Indications of fractures were seen from cuttings and gas shows obtained by mud loggers on a previous well. The intention was to drill this well perpendicular to the fracture planes to intersect multiple fractures and maximize production.

OXY wanted to record borehole images in the reservoir section for fracture evaluation. Fracture orientation would show if the well trajectory was optimal for intersecting the maximum number of fractures. Knowledge of fracture frequency, size and location along the horizontal section could be useful for future completion design, reservoir engineering and remedial work.

Ideally, the wireline FMI Fullbore Formation MicroImager tool would have been run, but practical considerations precluded this option. Wireline tools can be conveyed downhole by drillpipe or by coiled tubing in high-deviation or horizontal wells, but pressure-control requirements prevented the use of drillpipe conveyance in this case and coiled tubing was considered too costly. Also, calculations showed that helical coiled tubing lockup would occur before reaching the end of the long horizontal section. So OXY decided to try the RAB tool.

The first lateral well was drilled due north to cut assumed fracture planes at right angles. During drilling, images were recorded over about 2000 ft [600 m] of the 81/2-in. horizontal hole. After each bit run the data were dumped to a surface workstation and examined using FracView software.

Images clearly showed the characteristic sinuosoids of contrasting colors, indicating changes in resistivity as the borehole crosses bed boundaries (right).

Spring 1996
Although the resolution of the RAB tool is not high enough to see microfractures, several individual major fractures and clusters of smaller fractures were clearly seen (top right), providing enough evidence that the well trajectory was nearly perpendicular to the fracture trend.\(^7\)

Based on this information the second lateral was drilled south 10° east, again to intersect as many fractures as possible at 90°.

Images of California
Complex tectonic activity in southern California, USA, has continued throughout the Tertiary period to the present time. This activity influences offshore Miocene reservoirs where folding and tilting affect reservoir structure. Production is from fractured, cherty, dolomitic and siliceous zones through wellbores that are often drilled at high angle.

Wireline logs are run for formation evaluation and fracture and structural analysis—although in some cases they have to be conveyed downhole on the TLC Tough Logging Conditions system.

The CDR Compensated Dual Resistivity tool was used to record resistivity and gamma ray logs for correlation while drilling. The oil company wanted to evaluate using the RAB tool primarily for correlation, but also wanted to assess the quality of images produced. In fact, it was the images that, in the end, generated the most interest.

Good-quality FMI logs were available, allowing direct comparison with RAB images (right).\(^8\) Both showed large-scale events, such as folded beds, that were several feet long, as well as regular bedding planes. However, beds less than a few inches thick were not seen clearly by RAB images.

(continued on page 12)

\(^7\) The size of fractures seen by the RAB tool depends on several factors. The physical diameter of the button is 1 in. [2.54 cm], which produces an electric field slightly larger—1.5 in. [3.81 cm] in diameter. Conductive zones thinner than 1.5 in. can be detected, however, resistive zones need to be larger than this to be detected. Typically fractures with apertures around 1-in. can be detected if the borehole fluid is conductive.

Laterologs have their roots in a tool called the short normal, one of the earliest wireline logging tools. Its principles were adapted by many measurements-while-drilling (MWD) companies in the early 1980s to provide a simple resistivity log for correlation. The idea is fairly straightforward: force current from a source electrode to a return electrode through the formation; measure the current and voltage drop between the electrodes and use Ohm’s law to derive formation resistivity. However, for accurate petrophysical analysis in complex formations, more sophisticated devices are needed to measure true formation resistivity, \( R_t \).

An improvement on the short normal is the laterolog technique commonly used in wireline logging. Exploration Logging introduced a laterolog LWD resistivity tool in 1987 based on the laterolog 3 wireline tool of the early 1950s. This FCR Focused Current Resistivity tool had two additional current electrodes on either side of the measurement electrode. They provided guard currents that forced the main current deeper into the formation to measure \( R_t \).

At about this time, another approach was developed by Gearhart Geodata Services Ltd. from an idea by JJ Arps. The Gearhart Dual Resistivity MWD tool used a toroidal-coil transmitter to generate a voltage gap in a drill collar, which causes an axial current to flow along the collar. This method is ideally suited to LWD because resistivity tools have to be built into mechanically strong steel collars. Below the transmitter, current leaves the tool radially from the collar and axially from the drill bit. The amount of current leaving the collar at any point depends on the induced drive-voltage and the local formation resistivity. Two resistivity measurements are made: a focused lateral resistivity measurement and a trend resistivity measurement at the bit. Two receiver toroids, 6 in. apart, each measure axial current flowing past them down the collar. The difference in axial current equals the radial current leaving the drill collar between the two receivers and is used to calculate lateral resistivity. Bit resistivity is derived from the axial current measured by the lower receiver.

Schlumberger also uses the Arps principle of generating and monitoring axial-current flow in the RAB tool. However, radial-current flow is measured directly, and multiple toroidal transmitters and receivers are used in a unique focusing technique described later.

---

2. Arps, reference 5 main text.
RAB Tool—The Works
The RAB tool measures five resistivity values—bit, ring and three button resistivities—as well as gamma ray, plus axial and transverse shock.3 Built on a 6.75-in. drill collar, the 10-ft [3-m] long tool can be configured as a near-bit or in-line stabilizer, or as a slick drill collar (right). When real-time data are required, the RAB tool communicates with a PowerPulse MWD telemetry tool via wireless telemetry or a standard downhole tool bus, allowing total BHA design flexibility. However, it must be configured as a stabilizer for imaging.

Bit Resistivity—A 1500-Hz alternating current is driven through a toroidal-coil transmitter, 1 ft [30 cm] from the bottom of the tool, that induces a voltage in the collar below. Current flows through the collar, out through the bit and into the formation, returning to the collar far up the drillstring (below right). Knowing the voltage and measuring the axial current through the bit determines resistivity at the bit. Corrections are made for tool geometry, which varies according to the BHA.

The resolution of the bit measurement depends on the distance between the transmitter and the bit face—the bit electrode length. When the RAB tool is run on top of the bit, the resolution is about 2 ft [60 cm]. As the bit-resistivity measurement is not actively focused, the current patterns and volume of investigation are affected by nearby beds of contrasting resistivity. As wellbore inclination increases, the effective length of the bit electrode becomes shorter and, in horizontal wells, equals hole diameter.

Bit resistivity relies on a good bit-to-formation electrical path. The path is always excellent in water-base mud and generally sufficient in oil-base mud.

Applications for the bit-resistivity measurement include geostopping to precisely stop at casing or coring point picks. For example, in a Gulf of Mexico well the objective was to drill only a few inches into the reservoir before setting casing. An induction gamma ray log from a nearby well was available for correlation.

Drilling was stopped when bit resistivity increased to 4 ohm-m, indicating reservoir penetration (next page, bottom). Subsequent modeling showed that the bit had cut only 9 in. [23 cm] into the reservoir.

Focused Multidepth Resistivity—The RAB tool with button sleeve provides four multidepth focused resistivity measurements. For an 8 1/2-in. bit, the ring electrode has a depth of investigation of about 9 in., and the three 1-in. buttons have depths of investigation of about 1 in., 3 in. and 5 in. [2.5, 7.6 and 12.7 cm] from the borehole wall into the formation. Button resistivity measurements are azimuthal and acquire resistivity profiles as the tool rotates in the borehole. The sampling rate dictates that a full profile is acquired at rotational speeds above 30 rpm—generally not a limitation.

Data from the azimuthal scans are stored downhole and dumped from the tool between bit runs. In addition, the azimuthal data may be averaged by quadrant and transmitted to surface in real time along with the ring and bit resistivity, and gamma ray measurements.

All four resistivities use the same measurement principle: current from the upper transmitter flows down the collar and out into the formation, leaving the collar surface at 90° along its length. The return path is along the collar above the transmitter. The amount of current leaving the RAB tool at the ring and button electrodes is measured by a low-impedance circuit. Axial current flowing down the collar is measured at the ring electrode and at the lower transmitter. These measurements are repeated for the lower transmitter.

Cylindrical Focusing—In a homogeneous formation, the equipotential surfaces near the button and ring electrodes on the RAB tool are cylindrical. However, in layered formations, this is no longer the case. Current will be squeezed into conductive beds distorting the electric field (next page, top). By contrast, resistive beds will have the opposite effect: the current avoids them and takes the more conductive path. These artifacts are called squeeze and antisqueeze, respectively, and lead to characteristic measurement overshoots at bed boundaries called horns.
Nonfocused System

Active Focusing

Cylindrical focusing technique. A conductive bed below the ring electrode causes currents to distort in a nonfocused system (left). With active focusing, the current paths penetrate the formation radially at the ring electrode and almost radially at the three button electrodes (right). Radial currents are measured at the ring electrode, R, and at each button, BS, BM, BD, for each transmission. Also the axial current is measured at the ring electrode by a monitor toroid, M0, and at the lower transmitter by a monitor toroid, M2. There is no monitor toroid at the upper transmitter, the axial current there, M1, is assumed equal to M2 by symmetry. Software translates these measurements into adjustments of transmitter strength so that the axial currents at M0 cancel.

The cylindrical focusing technique (CFT) measures and compensates for this distortion, restoring the cylindrical geometry of the equipotential surfaces in front of the measurement electrodes. Focusing is achieved by combining the current patterns generated by the upper and lower transmitters in software to effectively impose a zero-axial-flow condition at the ring monitor electrode. This ensures that the ring current is focused into the formation and that no current flows along the borehole.4

Wireless Telemetry—Data from the RAB tool may be stored in nonvolatile memory or transmitted uphole via the PowerPulse MWD telemetry tool. Data are transferred to the PowerPulse tool by a downhole telemetry bus connection or a wireless electromagnetic link. In the latter case, the RAB tool transmits data to a receiver module connected to the PowerPulse tool up to 150 ft [45 m] away.


□ “Geostopping.” One advantage of a correlation tool that measures resistivity right at the bit is the ability to recognize marker beds almost as soon as the drill bit penetrates. This allows drilling to stop precisely at casing or coring points. In this example, the bit penetrated only 9 in. into the reservoir.
Analysis of cores indicated wide distribution of fractures throughout the reservoir with apertures varying from less than 0.001 in. [0.025 mm] to 0.1 in. [2.5 mm]. The button electrodes that produce RAB images are large in comparison—1 in. in diameter. However, even with low-resistivity contrast across the fractures, the largest fractures or densest groups of fractures that appear on the FMI images were seen on the RAB images (left). The RAB tool could not replace FMI data.

What intrigued the oil company, however, was the possibility of calculating dips from RAB images. If this were successful, then the RAB tool could help resolve structural changes, such as crossing a fault, during drilling. The suggestion was taken up by Anadrill. With commercial software, dips were calculated from RAB images. Good agreement was found between RAB and FMI dips.

Dip correlation during drilling proved useful on subsequent California wells. Many have complex structures, and the absence of clear lithologic markers during drilling means that the structural position of wells may become uncertain. Currently, RAB image data are downloaded when drillpipe is pulled out of the hole for a new bit and dips are subsequently calculated. The data are used to determine if the well is on course for the highly fractured target area (left).

The oil company’s experience with the RAB tool in these formations has shown that:
• RAB resistivity data are better in these formations than CDR data.
• RAB images compare well with FMI images, but cannot produce the fine detail required for fracture analysis.
• Dips can be calculated from RAB images, leading to structural interpretation.
• Dips calculated during drilling aid directional well control in highly faulted, high-angle, structurally complex wells.
• Dips determine when fault blocks are crossed and, hence, when to stop drilling.

The close cooperation between Anadrill, GeoQuest, Wireline & Testing and oil companies has led to the recent development of software to process RAB dips downhole. Dips may then be sent to surface during drilling for real-time structural interpretation.
Real-Time Dip Computation

Most conventional dip processing relies on crosscorrelation of resistivity traces generated as the dipmeter tool moves along the borehole (right). This type of processing works best when apparent dip is less than 70°—typical of most formations logged in vertical wells. However, in horizontal or high-angle wells, apparent dip will most likely be greater than 70°. This is the territory of LWD tools. Automatic dip computation in such situations is useful for geosteering applications in horizontal wells, especially if this can be done while drilling.

The new method uses the azimuthal resistivity traces generated by the three buttons of the RAB tool. Bedding planes crossing the borehole will normally appear twice on each trace as the buttons scan past the beds, first on one side of the hole and then the other. Dip computation is a two-part process that looks at where the beds appear on each trace and then where they appear between traces.

Where the bed appears depends on its azimuth with respect to the top of the RAB tool. The same bed will appear twice on the second and third traces, but will be displaced according to the dip magnitude. Finding the azimuth is simply a matter of correlating one half of each trace against the other half. Dip magnitude depends on the amount of event displacement between pairs of traces. Confidence in the computation is increased because three separate azimuths can be calculated—one for each button—and the three pairs of curves can be used independently for the dip magnitude computation.

The direction of dip—the azimuth—is calculated from the borehole orientation with

(continued on page 17)

## Evolution of the 2-MHz LWD Tool: From EWR to ARC5

<table>
<thead>
<tr>
<th>2-MHz propagation tool</th>
<th>Borehole-compensated propagation tool</th>
<th>Multiarray propagation tool</th>
<th>Multiarray BHC propagation tool</th>
<th>Multiarray MBHC propagation tool</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Directional sensor and pulser</td>
<td>34-in. transmitter</td>
<td>34-in. transmitter</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Drilling dynamics sensor</td>
<td>22-in. transmitter</td>
<td>22-in. transmitter</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Gamma ray</td>
<td>10-in. transmitter</td>
<td>10-in. transmitter</td>
</tr>
<tr>
<td>EWR tool</td>
<td>CDR tool</td>
<td>Wear bands</td>
<td>Receiver resistivity</td>
<td>Receiver 0 Measurement point</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>measurement point</td>
<td>Receiver</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Wear band</td>
<td>Wear band</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>35-in. spacing upper transmitter</td>
<td>35-in. spacing upper transmitter</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>15-in. spacing upper transmitter</td>
<td>15-in. spacing upper transmitter</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Receivers</td>
<td>Receiver</td>
<td>Receiver</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Transmitters</td>
<td>Resistivity measurement point</td>
<td>0 Measurement point</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Receiver</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Wear band</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>35-in. spacing lower transmitter</td>
<td>35-in. spacing lower transmitter</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1.5-ft crossover sub</td>
<td></td>
</tr>
</tbody>
</table>

In 1983, NL Industries introduced the first LWD tool to tackle induction-type environments. The EWR Electromagnetic Wave Resistivity tool has a 2-MHz transmitter and two receivers. The high frequency makes it an electromagnetic wave propagation tool rather than an induction tool. Induction tools measure the difference in magnetic field between the two receivers that is caused by induced formation eddy currents. Propagation tools, however, measure amplitude and phase differences between the receivers. All measurements can be transformed into resistivity readings. However, the EWR tool uses only the phase shift.

In 1988, Schlumberger introduced a borehole-compensated 2-MHz tool. This CDR Compensated Dual Resistivity tool has two transmitters symmetrically arranged around two receivers built into a drill collar. Each transmitter alternately broadcasts the electromagnetic waves: the phase shifts and attenuations are measured between the two receivers and averaged. The phase shift is transformed into a shallow resistivity measurement and the attenuation into a deep resistivity measurement.

The EWR tool described earlier was developed further by Sperry-Sun Drilling Services into a multispacing tool. This EWR-PHASE 4 tool consisted of four transmitters and two receivers providing four phase-shift resistivity measurements which, however, were not borehole compensated. A slimhole version—SLIM PHASE 4—was introduced in 1994. Halliburton also offers a slim 4.75-in. tool—the SCWR Slim Compensated Wave Resistivity tool.
Propagating the ARC5 Tool

The latest generation LWD propagation tool is the 4.75-in. ARC5 Array Resistivity Compensated tool, a self-contained 2-MHz multiarray borehole-compensated resistivity tool developed to log the increasing number of slim holes being drilled (above left). The array of five transmitters—three above and two below the receivers—broadcast in sequence providing five raw phase-shift and five raw attenuation measurements. In addition, there are gamma ray and transverse shock measurements.

Borehole compensation (BHC) is achieved by a method unique to the ARC5 tool. Standard BHC combines data from two transmitters placed symmetrically around the receiver array for one compensated measurement (above). The ARC5 tool dispenses with the second transmitter, relying instead on linear combinations of three sequentially spaced transmitters to provide what is called mixed borehole compensation (MBHC). The advantage of this system is that tool costs and length are reduced by eliminating five transmitters. Five MBHC phase shifts and attenuations are then transformed into five calibrated phase-shift and five calibrated attenuation resistivities (next page, top).

Borehole compensation (BHC) is achieved by a method unique to the ARC5 tool. Standard BHC combines data from two transmitters placed symmetrically around the receiver array for one compensated measurement (above). The ARC5 tool dispenses with the second transmitter, relying instead on linear combinations of three sequentially spaced transmitters to provide what is called mixed borehole compensation (MBHC). The advantage of this system is that tool costs and length are reduced by eliminating five transmitters. Five MBHC phase shifts and attenuations are then transformed into five calibrated phase-shift and five calibrated attenuation resistivities (next page, top).

**Oilfield Review**

**Why 2 MHz?**

A wireline induction tool generates an oscillating magnetic field—typically 10 to 40 kHz—that induces eddy currents in a conductive formation. These, in turn, generate a much weaker, secondary magnetic field that can be measured by a receiver coil set. Measuring the secondary magnetic field gives a direct measurement of conductivity—the higher the conductivity, the stronger the eddy currents, and the larger the secondary magnetic field.

Induction tools use a trick to cancel the primary magnetic field’s flux through the receiving coil set and allow measurement of the secondary magnetic field only. This is accomplished by arranging the exact number of turns and precise positions of the coils such that the total flux through them is zero in an insulating medium such as air. In a conductive formation, the flux from the secondary magnetic field doesn’t exactly cancel, so the induction tool becomes sensitive to the eddy currents only. If the same trick were tried on a drill collar, then similar precision for coil placement and dimensional stability would be required. In the harsh conditions of drilling, a drill collar striking the borehole wall can easily produce 100 g shocks—more than enough to ruin any precise coil positioning.

At 2 MHz, precise coil placement doesn’t matter, because the phase shift and attenuation are measurable with a simple pair of coils—both quantities increase rapidly with frequency. While the two receivers may be slightly affected by pressure, temperature and shock, borehole compensation completely cancels any such effects. Increasing the frequency further reduces the depth of investigation and leads to dielectric interpretation issues (left).
A Profile of Invasion

The ARC5 tool is a 4.75-in. slimhole, multi-spacing, 2-MHz, propagation LWD tool designed, in record time, to operate in 5.75- to 6.75-in. holes (see “Evolution of the 2-MHz LWD Tool: From EWR to ARC5,” page 14). Propagation LWD devices are similar in principle to wireline induction logging tools. They transmit electromagnetic waves that induce circular eddy currents in the formation and pair of receivers monitors the formation signal. At this stage, however, the physics of measurement similarities stops.

LWD propagation tools operate at 2 MHz, much higher than the 10- to 100-kHz frequencies of induction tools (see “Why 2 MHz?,” previous page). They are built on sturdy drill collars and are capable of withstanding the violent shocks imposed by drilling. Wireline induction tools are essentially built on well-insulated fiberglass mandrels that cannot tolerate such heavy handling.

However, they both perform best in similar environments, such as conductive and non-conductive muds and low-to-medium resistivity formations.

The ARC5 tool was designed to exploit interpretation methods developed for the wireline AIT Array Induction Imager Tool. To this end, both tools provide resistivity measurements at five different depths of investigation allowing radial resistivity imaging.

The ARC5 has other advantages over previous LWD propagation technologies including:

• improved estimation of Rt
• improved estimation of permeability index
• better evaluation of thin beds through improved resolution
• inversion of complex radial invasion profiles
• better interpretation of complex problems, such as invasion, resistivity anisotropy and dip occurring simultaneously
• reservoir characterization based on time-lapse logging.

Unique to the ARC5 tool is mixed-borehole compensation (MBHC). This method provides five MBHC attenuation and five MBHC phase resistivity measurements processed from only five transmitters. Standard borehole-compensation (BHC) requires 10 transmitters (see “Propagating the ARC5 Tool,” page 15).

respect to north plus the orientation of the bedding plane with respect to the borehole. For example, if on a trace, a bed appears to cut the borehole at 10° and 70°, then the orientation of the bed is 40° with respect to the top of the borehole. The second trace may see the same bed at 0° and 80° and the third trace, at 350° and 90°. Both give the orientation as 40° providing additional confidence in the calculation.

To determine the apparent dip, correlation is made between the three traces. In the above example, the bed appears on one side of the hole at 10°, 0° and 350° on each trace, respectively. As the distance between RAB buttons is fixed, simple geometry can be used to calculate apparent dip between any pair of traces. Knowing the borehole trajectory leads to true dip.

This method does not rely on data collected at different depths and is effective in horizontal wells. Also, the two-step approach of first calculating the dip azimuth and then dip magnitude provides a robust and fast algorithm that can be implemented in the tool microprocessor, allowing real-time transmission of structural dips (above).

A Profile of Invasion

The ARC5 tool is a 4.75-in. slimhole, multi-spacing, 2-MHz, propagation LWD tool designed, in record time, to operate in 5.75- to 6.75-in. holes (see “Evolution of the 2-MHz LWD Tool: From EWR to ARC5,” page 14). Propagation LWD devices are similar in principle to wireline induction logging tools. They transmit electromagnetic waves that induce circular eddy currents in the formation and pair of receivers monitors the formation signal. At this stage, however, the physics of measurement similarities stops.

LWD propagation tools operate at 2 MHz, much higher than the 10- to 100-kHz frequencies of induction tools (see “Why 2 MHz?,” previous page). They are built on sturdy drill collars and are capable of withstanding the violent shocks imposed by drilling. Wireline induction tools are essentially built on well-insulated fiberglass mandrels that cannot tolerate such heavy handling.

Raiders of the ARC5
A slim horizontal sidetrack in an offshore Middle East well provided a good field test for the ARC5 tool.1 Oil company objectives were to gain experience with horizontal drilling and to understand why more water than expected was being produced. The carbonate reservoir has major faults and several fractured zones, and is being produced under seawater injection.

The 6-in. sidetrack was drilled with the ARC5 tool run in record mode above the downhole motor in a steerable bottomhole assembly (BHA) and an interval of more than 2000 ft was logged from the kickoff point. Later, drillpipe-conveyed wireline logs were recorded over the same interval.

Comparisons were made between ARC5 phase resistivity readings and deep laterolog (LLD), shallow laterolog (LLS) and MicroSFL measurements recorded by the ARI Azimuthal Resistivity Imager and MicroSFL tools (left). Deep ARC5 phase resistivity curves, PH34 and PH28, agree well with LLD readings implying that applications for LWD propagation tools and laterolog tools overlap. The shallowest ARC5 curve, PH10, correlates with the LLS curve and reads much higher than the MicroSFL curve. Later processing suggests that there was little invasion at the time of drilling.

Wireline log interpretation indicates hydrocarbons throughout most of the interval. Water saturation is at a minimum from X1150 ft to X1250 ft, where ARC5 resistivities read higher than 100 ohm-m.

An invasion profile image produced from ARC5 data clearly shows the effects of drilling history, as well as formation permeability (left).12 For example, the interval from X2000 to X2050 ft shows increased invasion, because it was logged 24 hours
Imagine the Future

The ARC5 and RAB tools are part of a new generation of LWD resistivity tools capable of producing quality resistivity data for a wide variety of applications. Both introduce measurement techniques unique to LWD and wireline logging. For example, MBHC is a cost-effective alternative to doubling up on transmitters for borehole compensation and cylindrical focusing is a more stable alternative to traditional laterolog focusing (see “Cylindrical Focusing,” page 10).

With the development of INFORM Integrated Forward Modeling software, interpretation in horizontal wells will be greatly improved.13 Couple this with downhole dip processing and real-time imaging, and the arguments for resistivity-while-drilling measurements become powerful.

The value of LWD data will be further increased by close collaboration with Wireline & Testing and GeoQuest. For example, the concept of invasion-profile measurements leads to exciting possibilities. It offers a chance to look at the invasion process in detail. Resistive invasion infers water-filled porosity, whereas conductive invasion infers oil-filled porosity. In the near future, it should be possible to predict water cut and draw some conclusions about permeability directly from LWD fluid invasion-profile logging and resistivity anisotropy processing.

What is the next step in development? Although future possibilities are exciting for resistivity while drilling, the next step will be more evolutionary than revolutionary.

With the development of a family of different sized ARC5 and RAB tools, measurements described in this article can be applied to more borehole sizes. —AM

Drilling Summary

Drilling summary (top), ARC5 phase resistivities (middle) and resistivity image (bottom) shown in detail for the interval X1950 ft to X2200 ft. ARC5 data (middle) recorded 24 hr after a bit change show increased invasion (interval A) compared to the previous interval, which was logged only a few hours after being drilled. Little invasion occurs across a low-permeability streak (interval B). All resistivity curves converge (interval C) indicating water breakthrough.

after a bit change (above). Other intervals were logged within a few hours of drilling and show less invasion. Invasion is deeper where drilling is slow and also in high-permeability streaks. The latter coincide with the position of fractures and faults that are shown on FMI data.

Two intervals were of special interest to the oil company—around XX550 ft and X2080 ft. Formation resistivity approaching 1 ohm-m in both intervals indicated that seawater injection had broken through these zones. Increased pore pressure in these intervals resulted in dramatic increases in the rate of drilling. Several days later, the ARI tool showed that invasion had progressed to about 35 in. [89 cm].

The well was completed with a slotted liner and produced 4000 BOPD and 600 BWPD compared to 1000 BOPD in the original well. The interval at X2080 ft is the most likely contributor to water production.

13. INFORM software allows an analyst to construct a detailed model of the geometry and petrophysical properties of the formation layers along a well path. Simulated tool responses along the well are then compared to acquired log data allowing the model to be adjusted until they match. For a more detailed description:
In modern industry, quality is often discussed, but frequently misunderstood. The perception of quality—what it is and isn’t—varies widely from individual to individual and company to company. Oilfield service quality has received increased attention during the past decade as oil and gas operators strive to maximize hydrocarbon production and recovery at the lowest possible cost. This article illustrates how one drilling contractor, Sedco Forex, is infusing a quality culture and mindset in its organization to provide the best possible service.

Ellis Duncan
Ira Gervais
Channelview, Texas, USA

Yves Le Moign
Sunil Pangarkar
Bill Stibbs
Montrouge, France

Paul McMorran
Pau, France

Ed Nordquist
Dubai Petroleum Company
Dubai, UAE

Ted Pittman
Perth, Australia

Hal Schindler
Dubai, UAE

Phil Scott
Woodside Offshore Petroleum Pty. Ltd.
Perth, Australia

“We must define quality as ‘conformance to requirements’ if we are to manage it.”

What is your definition of quality? To some, it means fine craftsmanship, precision and attention to the smallest detail. For others, it’s consistency and reliability—something produced the same way time after time, something you can count on. For still others, it’s getting the best value for the money spent. Whatever your definition, you perceive a product or service to be of high quality—whether it’s a new automobile or how the waiter handles the orders and food delivery in the local restaurant—if it meets or exceeds your expectations. These expectations are often highly subjective. In the final analysis, quality is really obtaining what was promised by mutual agreement between provider and end user. For quality to be more than mere perception, however, requires established specifications—quantifiable standards or benchmarks against which the product or service can be measured objectively.

In the oil field, quality has taken on a new meaning and importance over the past decade. During the boom of the late 1970s, speed was all important. Wells were being drilled at a phenomenal pace; rigs were in short supply. How rapidly a contractor could move onto location, rig up, get the well drilled, rig down and move to the next site was, more often than not, the principal benchmark of a quality operation. However, the industry paid a premium price for this speedy delivery service, and the quality of the end product, the well, frequently suffered.

With the bust of the mid-1980s, the mentality of the industry changed drastically. Oil and gas operators were forced to look at ways to cut costs and squeeze the most out of every dollar spent. This was a prerequisite for survival and protection of the bottom line. Speed was no longer the prime determinant. It was replaced by a growing awareness that quality would be the single make or break factor in the future. Slowly at first, and then with increasing momentum, operators and service companies alike began to adopt the principles of quality that had, until then, been relegated to industries outside the oil patch. How the application of these principles by one particular drilling contractor provides dividends to its clients, its personnel and its operations is the focus of this article.

Have demonstrable results been achieved? Most assuredly they have been, as pointed out by the benefits gained in three diverse operating areas:
targets reductions in operational lost and down time, Woodside Offshore Petroleum Pty. Ltd. and Sedco Forex recently completed a development program 20% under budget (see “A New Approach to Quality and Efficiency in Australia,” page 29).

To fully understand the route to these improvements, we begin with the fundamentals of a quality culture—what they are and how they are implemented—and then investigate how such a culture has been established within Sedco Forex.

**Why the Emphasis on Quality?**

“The customer deserves to receive exactly what we have promised to deliver.”

The drilling industry has evolved significantly in terms of work scope and the division of responsibilities between oil companies and service suppliers. Much of the change has been driven by the proactive initiatives in drilling contracting that emerged early in the 1990s. Instead of the drilling contractor simply executing the task of drilling a well according to the specifications of the operator, a new way of doing business emerged. Closer communication links were established, and a coordinated, joint decision-making process was adopted for well planning. This has led to a better understanding of client needs and expectations than ever before, creation of benchmarks, and an improved image and credibility for the contractor who has become a true partner in an operational team.

Today, the focus is on reorganizing the way tasks are performed and toward reengineering the management structure and

---

interfaces. Safety and operational procedures are merging to bring suppliers together under a common system. New technology and communications methods are being applied universally, building greater rigsite efficiency. In short, much has changed and adapting to these changes has become a major challenge.

This evolution emphasizes client-oriented service and a commitment to do things right the first time and every time—the heart of a quality culture. It means eliminating unnecessary costs and losses that are the legacies of poor quality. Over time, a quality approach gains market share, increases profits and ensures competitiveness.

The Quality Evolution

"It is always cheaper to do the job right the first time." 4

Quality has evolved over four distinct stages (above left). When materials and manpower were cheap, engineers designed products not to fail by overengineering them with large safety margins. As materials became increasingly expensive, but manpower remained comparatively cheap, engineers designed products that met specifications without these extra margins of safety. While the probability of failure increased, intense inspection became the safeguard against delivering inferior products.

Then, when both materials and manpower became expensive, there was a reorientation toward understanding the processes to determine the causes of defects. Process control became the basis for minimizing the probability of failures. Finally, process control evolved into a more proactive approach in which planning for conformance from the start was the fundamental principle; analyzing contingencies and avoiding pitfalls at the design stage eliminated the need for corrective action later.

The last three stages of this evolution in quality are analogous to Quality Control, in which inspection was the order of the day; Quality Assurance, in which in-depth process analysis ruled; and finally, Quality Management, the current industry focus (left).5 Putting a quality-oriented management structure and culture in place is a major, long-term task, but one that reaps tremendous rewards.

The quality hierarchy. Quality management links all aspects of planning, control and improvement into a continuous system for ensuring conformance to established standards. (Adapted from Juran).

(continued on page 24)


5. For background on quality control and quality assurance:
The Sedco Forex Trident III (above left) jackup rig has been working for Dubai Petroleum Company (DPC), a subsidiary of Conoco, since the early 1980s. But, operations today are far different than they were over a decade ago.

In 1995, the Trident 18 (above right) joined the Trident III as the only other jackup rig working for DPC. The quality program implemented on the Trident III was one of the primary reasons the contract was awarded to the Trident 18, even though another drilling contractor had submitted a competitive bid. Also, instead of rebidding the Trident III contract in 1994, DPC and Sedco Forex worked together to renegotiate and extend the contract for two more years.

The Trident III and Trident 18 each typically drill eight to ten wells per year for DPC offshore Dubai in water depths ranging up to 200 ft [61 m] with well depths of 9000 to 18,000 ft [2750 to 5500 m]. Today, these wells are almost exclusively extended-reach and horizontal.

Recent experience on the Trident III and Trident 18 demonstrates how an oil company, working closely with the drilling contractor and other service suppliers on the rig, can bring an effective team approach to well planning and construction. It also points out the benefits to clients of having a comprehensive quality program as part of the drilling contractor’s culture.

Early on, Sedco Forex implemented a number of quality practices in the interest of continuous improvement, such as improved methods for handling towing lines during rig moves and for securing rigs, as well as installing test stumps for blowout preventers (BOPs). By pretesting BOPs on the stumps, there is a 4-hour savings in the time needed to install BOPs.

Starting in 1992, Sedco Forex began to track 60 distinct rig procedures under its control, such as the amount of time for tripping drillpipe and for running casing, to establish a series of benchmarks. After a quality improvement program based on this assessment was established, the time spent on these operations was reduced by 22% in 1993 compared to 1992, with a further 14% decrease in 1994 from 1993. In total, this adds up to a savings of over 120 hours per well, which is equivalent to drilling eleven wells in the same time previously needed for ten wells.

When problems arise on the rig, they are solved jointly through participation by all members of the team—from initial discussion to follow-up action. For example, new handling methods were put in place to avert the potential of discharging oily cuttings while drilling the pay zone. Also, the jackups were having difficulties with close alignments to the platforms. Analysis showed that revised operational procedures would increase their proximity and permit better access. This has allowed DPC to add more drilling slots to the platforms.

“When problems arise, there is teamwork in solving them,” says Hal Schlindler, District Manager for Sedco Forex. “No one is pointing the finger or trying to determine who’s at fault. Instead, the philosophy is ‘what does the team need to do to fix it?’”

Close communication and analysis between DPC, Sedco Forex and other service companies overcame difficult problems while drilling a troublesome shale section. During drilling of the shale, the well angle is typically built from 30 degrees to nearly horizontal. Problems were
encountered while running the 7-in. [17.8-cm] liner through this drilled section. Often, the liner could not be run to bottom and had to be pulled, and the section was then redrilled or sidetracked. Recommendations to overcome this problem included higher mud weights and drilling speed, and increased frequency of wiper trips. Since these modifications were implemented, all liners have been successfully run and landed without remedial operations.

According to Schindler, “Every manager from every company on the rig meets with DPC management each morning to review the morning report and the three-day forecast. We define and analyze problems on the spot, and by the end of the meeting, everyone leaves knowing exactly what their responsibilities are.”

Service Quality Appraisals are conducted on a quarterly basis, and the Trident III and Trident 18 averaged a remarkable 98% rating from DPC for 1995 (see “Service Quality at the Wellsite,” page 33).

“Performance tracking is invaluable,” says Schindler. “Looking at every aspect of the operation, in every possible way, pays dividends.”

In addition, the combined drilling team, made up of Sedco Forex and the other service providers on the rig, received Conoco Drilling Safety Excellence Awards for outstanding safety performance for the periods 1993-1994 and 1994-1995.

DPC Drilling Manager Ed Nordquist says, “One of the keys to the successful operation is the cooperation between DPC and Sedco Forex. However, this is becoming the norm today between operator and contractor. More important is the fact that Sedco Forex has been involved with DPC operations for a long time, and rig personnel know what we expect from them and are ready to deliver it.”

Quality Doesn’t Just Happen

“If quality isn’t ingrained in the organization, it will never happen.”

How does one go about changing a culture and infusing a new way of thinking and doing business in an industry that historically accepts change slowly, and often reluctantly? Change can be a daunting challenge and requires a concerted approach, nurtured by the top echelons of the organization and effectively transmitted through the rank and file. Specific, measurable objectives are prerequisites, and the task takes much time, patience and persistence.

Quality gurus, like W. Edwards Deming, Philip Crosby and Joseph Juran, have proposed a number of procedures for bringing a quality outlook to an organization. No single approach is necessarily superior, for they all have many fundamentals in common. Whatever route is chosen, the basic principles of quality will apply, adapted, of necessity, to fit the particular industry and company structure. To be successful though, a cultural change must evolve through three distinct phases (below).

- Conviction—deciding something needs changing
- Commitment—demonstrating a serious desire to change
- Conversion—embracing the change.

All three elements are critical. Without conviction, the effort will never get off the ground. Without commitment, once the process has started, it will dwindle and fall short of its aims. But once conversion has been achieved, the converted stay converted, and there is no return to the shortcuts or deficiencies of the past. Achieving the ultimate goal requires the implementation of a Quality Management System (QMS), one that is grounded in a number of key principles (above).

For a QMS to be successful, it must be simple and well-defined so that it can be understood and effectively communicated to all participants through a comprehensive awareness program and, as a result, become all-pervasive within the organization. The QMS must focus both inwardly and outwardly and be simultaneously employee- and client-oriented. Internal procedures need to be systematic, and application must be consistent. Actions should be proactive, not reactive, constantly seizing the initiative rather than waiting for events to happen. It must foster an environment of cooperation, mutual goal-setting and teamwork where all employees are empowered not only to participate in the system but also to contribute in demonstrable ways to achieve established goals. Above all, there must be a
commitment to continuous improvement in all areas.

The basis for continuous improvement is the belief that within any situation or any activity there is room to improve. The goal is perfection or “zero defects,” nothing less. The road to achieving this passes through three specific stages (right). In the first stage, the Present Situation, the status quo is investigated to fully understand where an opportunity exists for improvement, defining the driving forces for change and whether change is really worthwhile.

In the second stage, the Preferred Situation, potential solutions to the improvement opportunity are analyzed and the optimal one chosen. This stage focuses on defining factors that could inhibit successful implementation of the change and, therefore, require selection of an alternate strategy.

In the third stage, Action, proof of the validity of the investigation and the planning of the two previous stages are confirmed. The solution is implemented, and its success is monitored to ensure that what is achieved is what was expected. The cycle then repeats, focusing on additional opportunities for further improvement. The overall process increases efficiency and competitiveness, reveals opportunities that might otherwise be overlooked and promotes teamwork and proactive problem solving. This leads to the ultimate goal of Total Quality Management (TQM) in which every person and every activity in an organization contribute to the achievement of overall quality objectives. This open and honest culture includes standard systems for recording, investigating, implementing and monitoring improvement opportunities. The goal, again, is to get things right the first time, every time.

The Case for Quality Certification

“Quality management is needed because nothing is simple anymore, if indeed it ever was.”

Today’s complex world has led many to seek ways to safeguard quality through set procedures and controls. The main body that assists industry in doing so is the International Organization for Standardization, based in Geneva, Switzerland, with its ISO 9000 family of programs—the recognized standard for a quality system. ISO 9000 is concerned with process (what is supposed to happen, how it is supposed to be done, who is supposed to do it, where it is to occur and when) rather than the product itself. ISO certification assures that a business does what it claims to, that this can be documented, and that problems will be resolved, not ignored. It has nothing to do with approving a product or service. Implementation of an ISO 9000 system is based on identifying and understanding customers’ requirements and systematizing the methods and procedures necessary for meeting their needs, even as these needs change. These procedures are then documented in a reference quality manual.

Standards, in general, imply specification (against which a product can be measured to establish if it meets the standard), commonality, and some recognized method of assessment. Achieving ISO certification involves (1) design and implementation of a quality system that meets the requirements of the standard, and (2) a successful assessment completed by a suitable assessor body. The benefits of having a quality system in place, which include improved efficiency and assuring a constant level of quality, can result in reduced production and inspection costs. Furthermore, by providing assurance that a business will correctly meet customer requirements in a timely manner, compliance with an internationally recognized quality standard can increase confidence in a supplier, particularly when it may be located in another country.

As will be seen in the next section, ISO certification has become an integral part of the Sedco Forex drive to develop a corporate quality culture.

Offshore field development economics are influenced significantly by the size and weight of the platforms deployed and their installation times. In the N’Kossa field, West Africa, where water depths range to 590 ft [180 m], Elf and Sedco Forex have worked jointly to improve economics by reducing the time and costs involved in, and by increasing the efficiency of, platform installation and well construction.

The N’Kossa field was to be developed with two platforms. Elf wanted several wells drilled in advance, so that as soon as platform jackets, deck equipment and production facilities—in this case, a barge as the main gathering center, offloading to a tanker—were in place, production could commence from both platforms at near maximum rates. The field would, thereby, generate significant revenue while the remaining wells were drilled and placed on stream. To achieve this objective, Elf and Sedco Forex tackled the project with a coordinated team approach.

From start to finish, the emphasis was on quality and communication. Beginning in the spring of 1994, both companies appointed special project teams to work together on all phases of development. Communication channels were established, and formal and informal group meetings were held at regular intervals.

The development plan for the N’Kossa field consisted of four phases:

- First, prior to mobilizing the rigs to West Africa, the modifications and upgrades that were required for both drilling campaigns were carried out while the rigs underwent shipyard refurbishments in Rotterdam.
- Second, two subsea templates were preset and several wells predrilled through them using the semisubmersibles Sedco 700 and Sedneth 701, after which the platform jackets were installed.
- Third, the aft sections of the two semis were modified to accommodate heavy-lift cranes for use in installing derrick sets on the platforms.
- Fourth, two specially designed, modular derrick sets were constructed and transported to location for placement on the platforms using the reconfigured semis.

In addition to the crane installations, modifications to the semis included changing power and fluid lines to permit tender-assisted operations during the subsequent drilling phase of the project, when umbilicals would connect the semis to the derrick sets; reconfiguring the subsea BOP stacks to a surface stack arrangement; and repositioning the lifeboats so that the aft sections of the semisubmersibles could face the platforms directly during derrick set placement and during operation in the tender-assisted mode.¹

The Elf and Sedco Forex teams devoted much of their time and effort to the design and logistics associated with the derrick sets, covering the entire spectrum from conceptual design to detailed engineering, construction, movement to location...
and, finally, installation on the platforms. During the construction phase, procedures were defined to ensure compliance with specifications of all components received from vendors and for quality control and inspection. Detailed acceptance test procedures were issued in conformance with ISO 9001 guidelines. Elf had a representative present at all times overseeing construction and witnessing inspections and component testing.

Problems or discrepancies were resolved via direct communications between Elf, Sedco Forex, other service companies and parts vendors. A final debriefing and quality check was held with all service companies involved prior to shipment of the derrick sets to West Africa.

The 700-ton, self-erecting, modular derrick sets were designed to be as integrated and compact as possible to 1) minimize the number of crane lifts during installation, thereby eliminating as many peripheral small lifts as possible, 2) limit the number of connections and tie-ins to reduce lost time and potential problems due to dynamic motion of the semis, and 3) minimize dead time during the loading from the semis to the platforms. Placement would include a total of 14 lifts each, with the heaviest being 93 tons.

Several special features were included. The derrick sets were designed to adapt to the jacket configuration used in West Africa—with jacket rails perpendicular to the tender-support vessel—or to jackets with rails parallel to the tender and to be drip-proof, with all runoff collected at a central point and then pumped to the tender-support vessel for separation and disposal. On the tender-support vessel, the shale-shaker cuttings are deoilied using a cuttings dryer installation based on centrifugation of a mixture of base oil and cuttings.

Stainless steel was used for low-pressure piping and the drilling shelter to minimize corrosion. Drilling controls were ergonomically designed for comfort and efficiency, with a 180-degree view of the rig floor and derrick provided for the driller. BOPs could be repositioned without breaking out well-control lines, and handling facilities for the BOPs allowed the wellhead to be lifted and installed preassembled. Fast-connect couplings were used throughout to minimize downtime in the nipping up of the BOP stack to the wellhead, and quick-disconnect couplings were used on hydraulic control circuits to minimize both oil spillage and downtime.

Construction began in France in October 1994, with both derrick sets fabricated simultaneously (previous page). Construction was completed in May 1995, and the units were shipped by river barges to the French coast and offloaded onto an ocean-going barge for the trip to West Africa. Transit time was 24 days. The barges were anchored alongside the semisubmersibles, and the derrick sets were offloaded onto the decks of the semis with the heavy-lift cranes. The two semis were then towed to the N'Kossa field, anchored on location, and the derrick sets were offloaded and rigged up. The process, from derrick set arrival to final installation, took 25 days. At present, the predrilled wells are being tied-back to surface wellheads on the platforms and completed, while awaiting the arrival of the production barge and final preparations for drilling additional wells.

As a result of the coordinated team approach and an overriding commitment to quality in all aspects of the project by both operator and drilling contractor, the following economic benefits were realized:

• The decision to contract two rigs at the same time with almost identical features allowed Elf to optimize the field development plan for both predrilling (stand-alone mode) and tender-assisted drilling mode.

• The decision to modify the semis saved significant rig-up and installation time, and cost compared to the option of securing an expensive crane barge.

• Use of a tender-assisted configuration, with key support and accommodation facilities on the semis, enabled Elf to minimize the size, weight and cost of the platforms.

• The modular and flexible design features of the derrick sets provide enhanced capabilities, as well as lower maintenance and operating costs.

Improvement comes with each step of the overall program."

Sedco Forex is one of the largest drilling contractors in the world, employing 5100 people of 50 nationalities and operating 42 offshore and 34 land rigs in 26 countries. With such a far-flung organization and cultural diversity, implementing a universal quality program represented a formidable task. As with any company committed to installing a quality program, Sedco Forex began with the tools at hand. The starting point was the company's health, safety and environment (HSE) system, which was recognized as a model within the drilling contractor industry.

Over the years, Sedco Forex had developed a comprehensive HSE Management System that included policies, procedures, tracking mechanisms and compliance assessment methods (above right). This system had its origins in a Safety Management System (SMS) which had received considerable attention from industry peers in the late 1980s.

In 1986, Schlumberger management committed to a 50% reduction, over a five-year period, in the drilling lost-time injury (LTI) frequency rate—as defined and reported by the International Association of Drilling Contractors (IADC)—as a show of the corporation's dedication to safer drilling operations in the industry.13 This commitment motivated the staff and paved the way for a revitalized safety awareness program in which safety activities grew more focused, professional and proactive. Results improved and the target was achieved.

The safety system proved to be a good starting point, first for HSE and then for quality efforts. Much of what was needed was already in place. Over time, managers recognized that every aspect of operations could profit from the quality drive. Analysis of accidents and operating failures pointed out the need for better tracking and for closing the loop with specific solutions. Still lacking, however, was a mechanism for identifying the cost of quality nonconformance and quantitative measurements of real losses.

In general, other than IADC statistics, there are few internationally recognized benchmarks for the drilling industry. This meant that Sedco Forex had to define and implement its own set of benchmarks. This has been done. Each year, targets are set for key indicators, and these targets become integral to the company's objectives, on a par with financial goals.

The system is simple and focused. Fatalities, LTIs and major losses, as well as compliance with HSE training, identification of risks and service quality appraisals are tracked and analyzed at headquarters. Results are regularly summarized and communicated to the field. Deeper into the field organization, the number of benchmarks increases accordingly, finally reaching rigid specific needs. For the first time, a systematic and coordinated effort is being used to quantify and understand losses in real financial terms.

ISO certification of selected locations has helped further emphasize the drive toward a quality culture. Operations in Aberdeen, Scotland and Brazil, the Engineering Department in Montrouge, France, and the logistics and supply center in Channelview, Texas, USA, have been awarded ISO certification (see “The Road to ISO Certification,” page 32).

13. A lost-time injury is any work-related injury resulting from an accident that prevents the person from continuing, in the next following shift, the same job that he or she was performing before the injury. The frequency rate is expressed as the number of incidents per million person-hours worked.
A New Approach to Quality and Efficiency in Australia

In 1993, Woodside Offshore Petroleum Pty. Ltd. committed to improve its offshore well construction performance on the Northwest Shelf of Australia. The company’s analysis of operations conducted from 1986 to 1992 showed erratic results, with high average drilling times compared to published benchmarks.

For the upcoming Wanaea and Cossack developments in 270 ft [82 m] of water, which would include directional wells and the first-ever subsea completions for the company, Woodside instituted an aggressive target-setting and planning methodology, based on asking the question “What is possible?” instead of “How can we improve?” The approach had a central philosophy: targeting the “technical limit,” a level of performance judged as the best possible for a given set of parameters (right). Implementation of such a radical change in thinking required an extraordinary effort and commitment, and the building of new relationships with the drilling contractor and other service suppliers, founded on teamwork and effective communications.

Studies by Woodside had pointed out the critical importance of the drilling rig’s specifications. The cost of higher level rig specifications could easily be justified if the added capabilities translated into significant efficiency gains toward the goal of achieving the theoretical minimum well time, the technical limit. This permitted “fit-for-purpose” rig selection and sole source negotiation of the selected rig, eliminating the need for a low-bid tendering process. Working with Woodside, Sedco Forex assessed rig options that would deliver the desired specifications, and the Sedco 702 semisubmersible was selected for the project.

Sedco Forex was involved from the outset in the extensive planning phase that spanned a period of nine months. The company placed a former rig superintendent in the Woodside office to liaise directly with Woodside’s engineers and design team. The emphasis was on developing benchmarks—the technical limits—optimizing the operational process and communicating the plan and process to everyone involved, including roustabouts on the rig, to enlist their commitment and ownership. Start-up seminars and regular, joint management visits and presentations helped facilitate and underscore the communication process. Throughout, a “no-blame” culture was adopted by Woodside in all its dealings with service suppliers, a culture that encouraged problem solving rather than finger pointing.

Critical path thinking was adopted during the assessment phase. All activities that could affect the critical path, either positively or negatively, were identified and analyzed. Much of the effort focused on areas normally defined as conventional down time and lost time. But, studies went further to concentrate on what became known as “invisible lost time,” inefficiencies targeted for the first time using the technical limit approach.

The process resulted in improved procedures and techniques that speeded operations. For example, subsea trees were normally assembled and pressure tested in the moonpool of the semisubmersible, inhibiting other activities. Tree and tree-handling operations were removed from the moonpool area for improved efficiency. During drilling, running of the drilling riser and BOPs was streamlined with better make up of lifting subs and pickup procedures. Where possible, bottomhole assembly (BHA) components were made up off-line, allowing pickup and mounting of the BHA in one piece using a specially designed roller system.

Applying this methodology, Woodside drilled three new wells and installed six subsea completions 20% under budget. By successfully reducing lost and down time and increasing the percentage of effective time, they were able to drill the third well in the project in 20 fewer days than the first.

“Everything we did targeted process optimization and control. It has been enormously satisfying to see our team of people from different companies pull together—and in the same direction—to achieve top-class results,” says Phil Scott, Well Construction Manager for Woodside. According to Ted Pittman, Sedco Forex District Manager, “The way the team worked together can best be summed up in the project motto: ‘Pride in Performance.’ From the start, it motivated all members of the team and kept us continually focused on quality and efficiency.”

---

Uniting all aspects of the QMS is the recently issued Quality Manual, which defines a consistent methodology for the pursuit, tracking and structure of the quality effort and emphasizes measurement, communication and continuous improvement (above). The HSE and quality functions have been merged into a universal Q-HSE function for coordinating and managing the quality system. The focus is constantly on the three prime elements, or dimensions, that must be considered in every quality activity—product, process and people (below). These elements provide the foundation for the new quality culture.

A corporate definition of quality has emerged: “Giving the client what he wants, when he wants it, at a mutually agreed cost.” This entails defining and meeting the client’s specifications and expectations; keeping to schedules, programs and project plans; and satisfying the financial requirements of both parties. Specifications must be agreed to in advance, must be backed up by an effective delivery system and must never be less stringent than the internal Q-HSE guidelines established within Sedco Forex. The remainder of this article focuses on the implementation of specific Sedco Forex quality programs in training, engineering and field operations.

Changing the Training Focus

“Think of change as skill-building and concentrate on training as part of the change process.”

Thanks to new technology and greater rig automation, drilling today is less demanding physically than a decade ago. But, it still remains a dangerous business. This is why comprehensive training has always received top priority.

Within Sedco Forex, four training centers (see “The French (Training) Connection,” page 34) provide formal courses for new and experienced personnel. A follow-up system ensures proper application of new skills. Roving instructors visit rigs and check for safe work practices. Each rig has safety committees that set standards, hold regular information and problem-solving meetings, and track compliance. Data bases have been developed and are constantly updated to communicate risk information and profile critical risk areas. Health and safety campaigns are mounted to target areas where improvement is needed. Initiatives, like the Dupont STOP program, a systematic approach to recognizing potential problems and addressing them before they turn into incidents, provide quality focal points for rig personnel.

Within the training effort, benchmarking has been critical. Monthly measurements of compliance in areas such as HSE and well-control training, providing feedback, and developing action plans to rectify deficiencies have been at the heart of the program.

Without a focused training effort in quality as the end goal.

Reengineering Engineering

“There is absolutely no reason for having errors or defects in any product or service.”

While some aspects of drilling operations have changed little over the past 50 years, technological advances, such as top drives, improved downhole motors, and logging-and measurements-while-drilling techniques, have had a pronounced influence on efficiency and cost. Ensuring rapid and effective development of new technology and its transfer to the rigsite requires a quality approach within the engineering organization of the drilling contractor.
**Management training matrix.** The matrix outlines priority courses and essential supplementary programs for training rig personnel and regional management in quality, providing instruction on improving supervision, problem identification and communications.

<table>
<thead>
<tr>
<th>Courses run by Sedco Forex &amp; Courses shared with sister Schlumberger companies &amp; Outside courses</th>
<th>Rig</th>
<th>Rig engineers</th>
<th>Rig superintendents</th>
<th>Rig managers</th>
<th>District managers</th>
<th>Project managers</th>
</tr>
</thead>
<tbody>
<tr>
<td>BEST 1</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Management 1</td>
<td>1</td>
<td>2</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Communication skills</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Train the trainer</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>IT module</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>TQM awareness</td>
<td>1</td>
<td>2</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Management 2</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Sales training 1</td>
<td>as needed</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Sales training 2</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>BEST 3 - Finance</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Financial analysis</td>
<td>as needed</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>BEST 3 - Project mgt</td>
<td>as needed</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Bidding workshop</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Advanced mkt seminar</td>
<td>as needed</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Advanced mgt seminar</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Presentation skills</td>
<td>as needed</td>
<td>as needed</td>
<td>as needed</td>
<td>as needed</td>
<td>as needed</td>
<td>as needed</td>
</tr>
<tr>
<td>Recruiting skills</td>
<td>as needed</td>
<td>as needed</td>
<td>as needed</td>
<td>as needed</td>
<td>as needed</td>
<td>as needed</td>
</tr>
</tbody>
</table>

Courses run by Sedco Forex • Courses shared with sister Schlumberger companies • Outside courses

1. Priority 1: High priority training and highly recommended
2. Priority 2: Lower priority training but also recommended
   as needed
3. Where either the job or the development plan indicates the need
4. BEST Better Exempt Schlumberger Training

Management training matrix. The matrix outlines priority courses and essential supplementary programs for training rig personnel and regional management in quality, providing instruction on improving supervision, problem identification and communications.

For Sedco Forex, the engineering department is one of the sites that has achieved ISO recognition. But here the approach was initially directed at analyzing existing practices and developing innovative approaches to improve the quality and deliverability of new products and techniques. The goal was to have a practical, workable system in place, rather than to achieve ISO certification. However, in the drive to set up a quality system, ISO became viewed as the most effective means to this end. Certification was a natural outcome of the process.

Examples, ranging from electronic documentation to improved field support and shipyard construction and repair, highlight how recently introduced products and procedures are helping achieve more for the client.

If you’ve ever been on a drilling rig, you’ve seen the overwhelming number of printed technical and procedural manuals needed to support day-to-day operations. One engineering project focused on replacing these bulky, hard-copy manuals with electronic documentation on CD-ROM—saving storage space and streamlining the massive effort to keep them updated.

The first corporate documentation CD-ROM was sent to all rigs in December 1995 after pilot testing in four field locations in the Middle East and Far East. Each rig has been equipped with CD-ROM readers. A single CD contains 11 operations, Q-HSE and training manuals; 20 marine operations manuals; maintenance policies and procedures; and other location- and discipline-specific documents, for a total of 1664 files. Documents are linked; searches by key word and topic can be conducted; and a variety of navigation tools make finding key information straightforward and efficient. The contents of the CD will be updated and expanded regularly.

This approach to documentation ensures access to the most current information and improves the productivity and efficiency of rig workers by providing the data they require to perform their jobs, thus reducing errors, downtime and losses.

A second area of quality improvement has been in field support. Historically, when a problem arose on a rig, an engineer would ask for help from a contact in the engineering department. There were many potential pitfalls with this approach: the person might not be the right one to contact; descriptions of the problem might be incorrect or incomplete; similarly, the recommended solution might be incorrect or incomplete; or, finally, no action might be taken—the request simply being ignored.

To correct these deficiencies, new procedures were established, including a complete set of specifications and communication channels known as the Request for Engineering Action (REA) system. When help is needed, rig personnel describe the nature of the problem to the regional organization. The region then relays the request to an engineering point contact who determines the expert or group of experts best equipped to answer the question. If the problem can be solved faster and more efficiently outside the engineering organization, for example by using a consultant, the point contact will funnel the project accordingly.

Since at any one time there might be 60 to 80 such requests in process, priority setting is important, particularly with costly drilling times at stake. The REA system allows much tighter control over priorities and assignment of the proper sense of urgency—all features lacking in the previous system. The region and rig are both kept informed of progress toward, and the deadline for, a solution.

With the checks and balances involved, how rapidly are results delivered? The formalized procedures bypass many of the previous pinch points, and deliverability is as good or better. The key benefit is enhanced quality management of the solutions.

The quality system is also reaping benefits in shipyard construction and repair. Typically, shipyard activities were treated as one-off projects. Each time a new project came along, there was a tendency to reinvent the wheel. Today, a retrievable data base captures project information, allowing prior experience to be drawn on. Also, there is a formalized approach to project management and coordination, as well as document control.

Task force managers are appointed, and the scope of work is defined up-front. New communication channels facilitate early exchange of ideas. Staff and facilities benefit from better organization, which specifies

(continued on page 33)

In today’s marketplace, identifying and understanding a customer’s requirements and meeting those needs are critical for maintaining a competitive advantage and serve as underlying factors in the movement toward total quality management and implementation of quality systems. An effective system is one that has commitment to quality and continuous improvement at all levels of the company. Learning from mistakes and ensuring that problems do not recur are accomplished through problem identification (auditing), investigation (corrective action) and long-term rectification (controlled procedural change).

Sedco Forex prides itself on being close to its clients and providing innovative approaches to better meet their needs and reduce costs in drilling operations. Following the general movement of many businesses to comply with ISO 9000 standards and the specific desires of several customers to deal with ISO 9000-certified vendors and service providers, certain Sedco Forex facilities have sought and achieved ISO 9000 certification. In particular, in 1993, the Materials Logistics Center (International Chandlers, Jacintoport Facility) in Channelview, Texas, USA, outside of Houston, was the first within Sedco Forex, and the first distribution center of any kind in the USA, to achieve ISO 9000 certification (above right). Specifically, the center has been certified by Det Norske Veritas (DNV), the foremost certifying body, to conform to ISO 9002 quality system standards for “procurement and logistic services for oilfield equipment, spare parts, and consumables.” As the procurement center for the purchase and resupply of critical parts and materials for Sedco Forex rigs operating worldwide, this group plays a central role in minimizing drilling rig downtime. Rig time lost by errors in procuring or shipping replacement parts can significantly impact operational efficiency, profits, customer relations and company image.

The motivating factors behind the effort to seek ISO certification were threefold. “We felt that we could create a good quality system for our operation,” says Ellis Duncan, Materials Manager at the Jacintoport facility, that it “would be advantageous to our clients,” and that it would also “satisfy the needs of our North Sea operation” (right). On the first point, Ira Gervais, Jacintoport Quality Manager, points out that ISO certification is the facility’s first effort in developing a quality system. “We thought we were doing great,” he comments, but he also notes that there was no mechanism to identify what they were doing wrong when problems did arise. Discussing the advantages to their clients, Duncan says, “We wanted to be sure that if there was any question concerning the quality of our fleet in the North Sea, we could say that we are buying from suppliers through an ISO quality system.” Regarding the last factor, Duncan says that the need to stay competitive played a major role in the decision to seek ISO certification. “Major clients started pushing this in the North Sea.”

Although the Channelview facility went into ISO certification as a trial, taking a wait-and-see attitude, the experience and positive results paved the way for subsequent ISO certification of other Sedco Forex locations.

It’s difficult to compute exact dollars saved due to improvements resulting from the ISO-related changes. “How do you put a figure on accidentally purchasing the wrong part or an inferior product, or sending a part to the wrong place or...
the wrong rig, and ending up having to repurchase or reship a product," Gervais points out. ISO 9002 uses the combination of internal audits and periodic audits by an external organization to review procedures, documentation and corrective actions in purchasing, contracts, purchaser-supplier product control and process control. DNV, the auditing body for the Jacintoport facility, focuses on one of these areas during its semi-annual audits. The DNV auditors review paperwork to verify that the documented procedures are being followed and make spot checks of portions of the operation. "For example," Gervais says, "to avoid mistakes in shipping, we must specify how we handle noncompliant products when they come in. If they can’t be identified, we place them in a special location, properly tagged. DNV checks that on a regular basis. If something does go wrong, we must specify how we will correct the problem and isolate the nonconforming material in the future." A full recertification is performed every three years—with the next due in 1996 for the Jacintoport facility.

The quality manual, containing the documentation of procedures required for ISO certification, must describe what’s actually done in the business process, while at the same time not be overly burdensome to employees. The liberal use of flow charts and organizational charts has kept the Channelview quality manual to a concise and readable 35 pages, in comparison to other companies where such manuals may be several volumes in length. According to Gervais, "A side benefit of having all procedures documented in a manual is that new employees now have a reference and learn the proper procedures from the onset." The quality manual must be updated, and all employees must have access to the most current version. Depending on the size of a facility, maintaining and updating documentation can be complicated and cumbersome. In this area, the Channelview group has taken an innovative approach: their manual is accessible to employees through the Sedco Forex home page on the World Wide Web. "What we’ve done is put the official copy on our network," says Gervais. "It’s the official copy for downloading and printing."

Duncan indicates that the primary benefits of ISO certification for the Jacintoport facility are awareness, discipline and accountability. These are derived from the ISO 9000 requirements for establishing formal procedures for recognizing and handling problems, both internally and in the field, for accurate documentation and control of that documentation, and for taking corrective action. He says that prior to ISO certification, "There were no established procedures for making sure things were actually handled correctly. Now, when the field has any type of problem with something we handled, they fill out a procurement incident report and send it to us, and we have to correct it." One example involved changes in receiving and packing procedures to address complaints that supplies were arriving in the field wet or damaged. To ensure accountability and corrective action, the Jacintoport facility now sends out a semi-annual service quality analysis questionnaire to the field to learn how customers feel about their service. Documentation produced by this communication must be addressed and acted on; problems cannot be ignored. "Without a doubt, a key area is speed" says Duncan. "They want us to react quicker. We weren’t as accountable before. But you are with this system. It’s all documented. It’s all there. It’s all audible."

Since ISO certification, Jacintoport has received additional business from sister companies like Dowell for procuring, packing and shipping goods to the field. These companies could use anyone, but, Gervais says, ISO certification has allowed the Jacintoport facility to improve its systems and to demonstrate that "we’re very professional in what we do" and that mechanisms for redressing complaints are in place. — SP

Closing the feedback loop with the oil and gas operator is one key to ensuring a climate of continuous improvement. To aid in this goal, Sedco Forex implemented a Service Quality Appraisal (SQA) system three years ago. The system is based on a comprehensive set of guidelines. The first level, the SQA form, is filled out by the client (below). It provides a quantitative assessment of how the rig and its personnel stack up in several categories, including HSE, overall drilling performance, organization and skills of the personnel, condition and utility of the equipment, and quality of rigsite communications. The bottom line is an overall performance rating, or index, with a maximum score of 100%

The SQA covers a particular time period and is used by the rig manager to assess the operation and for discussion with clients in quarterly meetings. These sessions review the strengths and deficiencies of the service quality criteria for the shipyard, including testing and reporting procedures and detailed financial controls. ISO guidelines help to plug the holes and impose a schedule for fixing problems. In this example, as in others, it’s often a few simple improvements that together produce a significant increase in quality.

Service Quality at the Wellsite

"Think where your company could be if you completely eliminated failure costs." 17

The Pyrenees mountains form a spectacular backdrop to the Sedco Forex training center in a picturesque suburb of Pau, France. It is the largest, best-equipped and busiest of the four training centers the company operates worldwide. Sister facilities are located in Aberdeen, Scotland; Warri, Nigeria; and Singapore.

Today, with even greater emphasis on the health and safety of employees, protection of the environment, and quality, the center is fulfilling an expanded role that reflects the Sedco Forex commitment to training as a core element of the company’s culture.

The Pau site was originally established in 1949 as a base for North African and European drilling operations. Training courses were first conducted in 1972 and, during the nearly two and a half decades since, the training mandate has evolved and the course list has grown considerably, in line with the changing needs of the drilling industry and the profile of the company’s workforce.

Today, the extensive complex includes 10,800 ft² [1000 m²] of classrooms, workshops and office buildings, supported by 80,700 ft² [7500 m²] of yard space. Eight instructors and support staff provided 4400 man-days of training in the latest drilling technology during 1995. For 1996, that figure is expected to increase to 7000 man-days. There are four principal classrooms, one equipped with a state-of-the-art drilling simulator. This simulator, used primarily for instruction on well-control procedures, also models stuck pipe situations and various techniques for drilling optimization, and interfaces with an advanced computer system that allows trainees to access, and interact with, actual well data. Extensive computer and video facilities in the classrooms permit maximum use of new information technology tools and multimedia training aids.

The site’s most striking feature is also its principal piece of equipment—an ultraheavy, diesel-electric land rig with a rated drilling depth of 18,000 ft [5500 m] and a 600-ton capacity mast and substructure (above left). The size and capabilities provide a training tool unique in Europe. The rig is fully equipped with hoisting, rotating, circulating and well-control systems. It is positioned over a 4400 ft [1350 m] cased well, with casings ranging from conductor and surface strings to 9 ½ in. [25 cm] at total depth. The rig and well combination permits realistic simulation of a wide range of drilling conditions encountered daily in field operations.

The rig is fitted with a high-pressure air compression, storage and injection system. Air can be introduced into the well through tubing run outside the casing to simulate a gas influx (kick) on a live well. Each Sedco Forex drilling crew receives mandatory well-control training every two years, carried out to the certification standards of the International Well Control Forum, an organization representing operators, contractors and drilling schools around the world. Sedco Forex is a founding member of the group. The crews must be able to resolve a variety of well-control problems and successfully shut in and circulate out gas kicks to pass the course and be recertified (left).
Today, induction training for newly recruited drilling engineers and technicians, initiated in 1980, is the principal business of the training center. In a 19-day course for engineers and a 10-day course for technicians, which combine theory, classroom lectures, homework and practical exercises, the rig and well provide a controlled environment for hands-on training in the latest technology and operational techniques. Knowledge and skills developed during the course form the foundation necessary to ensure that new recruits perform safely and effectively in their first actual rig assignments.

A complete mechanical workshop maintains all critical pieces of drilling gear and gives trainees the opportunity to witness and participate in disassembly and major overhauls of both surface equipment and downhole tools during hands-on training sessions.

In addition to new trainee induction and well-control schools, the center schedules a variety of other courses. These include drilling technology courses, covering both the fundamentals of casing and cementing, directional drilling, drill bits, drillstring design, hydraulics and solids control, as well as advanced work on formation evaluation and well design. In addition, there are marine courses on the stability of offshore rigs and procedures for moving and operating offshore rigs.

For many years, Sedco Forex has been a recognized industry leader in training field personnel. Never has this been more evident than today, as reflected in the dedication shown by the training staff at Pau.

**Service Quality Index (SQI).** The SQI shows the overall rating achieved for a particular rig. In this example, the indices are for seven rigs for the second quarter of 1995.

<table>
<thead>
<tr>
<th>Rig</th>
<th>Total possible score</th>
<th>Actual score</th>
<th>Overall performance, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rig 1</td>
<td>180</td>
<td>152</td>
<td>84</td>
</tr>
<tr>
<td>Rig 2</td>
<td>180</td>
<td>137</td>
<td>76</td>
</tr>
<tr>
<td>Rig 3</td>
<td>180</td>
<td>136</td>
<td>76</td>
</tr>
<tr>
<td>Rig 4</td>
<td>168</td>
<td>154</td>
<td>92</td>
</tr>
<tr>
<td>Rig 5</td>
<td>180</td>
<td>167</td>
<td>93</td>
</tr>
<tr>
<td>Rig 6</td>
<td>176</td>
<td>135</td>
<td>77</td>
</tr>
<tr>
<td>Rig 7</td>
<td>180</td>
<td>138</td>
<td>77</td>
</tr>
</tbody>
</table>

**Closing the loop with the client.** The SQA and specific follow-up actions assure the degree and frequency of feedback necessary to keep the client informed and foster an environment of joint problem solving.

---

**The Journey is Only Beginning**

To develop and thrive, a corporate quality culture requires a never-ending journey along a route marked with road signs reading conviction, commitment and conversion. At times, the route is rough and winding, but every step forward brings substantive benefits for both clients and employees.

The words of Philip Crosby sum it up best. "Quality is an achievable, measurable, profitable entity that can be installed once you have commitment and understanding and are prepared for hard work." —DEO

---

Getting to the Root of Gas Migration

Of the two principal objectives facing primary cementing operations—casing support and zonal isolation—the latter usually raises the most concern, and is perhaps the hardest to achieve when there is potential for formation gas to migrate into the cement sheath. The challenge for industry is to achieve a long-term annular cement seal and prevent formation gas entry. Successful handling of gas migration is an evolving science. This article looks at causes, consequences, predictive methods, new solutions and the latest state of play.

Art Bonett  
*Cambridge, England*

Demos Pafitis  
*Sugar Land, Texas, USA*

Five years ago, an article in *Oilfield Review* stated, “Understanding gas intrusion is an evolutionary process that has not yet run its full course.”1 Since then, the evolution has continued, providing a more detailed picture of the downhole phenomena active during gas migration. Although many possible solutions are similar to those available in 1991, increased knowledge of gas entry mechanisms means that these solutions can now be deployed in a more logical and cost-effective way.

Gas invasion occurs when pressure is lower in the annulus than at the formation face. Gas then migrates either to a lower pressure formation or to the surface. The severity of the problem may range from residual gas pressure of a few psi at the wellhead to a blowout. Whatever the severity, the major factors contributing to gas migration are common. Successfully achieving a long-term annular cement seal begins by understanding these contributing factors.

---

For help in preparation of this article, thanks to Art Milne, Dowell, Clamart, France and Tom Griffin, Dowell, Sugar Land, Texas.

CemCADE, GASBLOK, GASRULE, VIP Mixer and WELLCLEAN are marks of Schlumberger. MicroVAX is a trademark of Digital Equipment Corp.
Fluid densities are too high. Also, consideration must be given to the free-fall or U-tubing phenomenon that occurs during cement jobs. Therefore, cement jobs should be designed using a placement computer simulator program to assure that the pressure at critical zones remains between the pore and fracture pressures during and immediately after the cement job.

Any density errors made while mixing a slurry on surface may induce large changes in critical slurry properties, such as rheology and setting time. Inconsistent mixing also results in placement of a nonuniform column of cement in the annulus that may lead to solids settling, free-water development or premature bridging in some parts of the annulus. This is why modern, process-controlled mixing systems that offer accurate density control are important.

In the past, various techniques have been developed to tackle individual factors that contribute to gas migration. However, gas migration is caused by numerous related factors. Only by addressing each factor systematically can a reasonable degree of success be expected. There is no single “magic bullet” for gas migration.

This article summarizes the current state of knowledge about gas migration, drawing on field expertise from Dowell, and on experimental work carried out predominantly at Schlumberger Cambridge Research (SCR) in England. Much of this experimental work is unpublished.

Setting the Scene
Successfully cementing a well that has potential for gas migration involves a wide range of parameters: fluid density, mud removal strategy, cement slurry design (including fluid-loss control and slurry free water), cement hydration processes, cement-casing-formation bonding and set cement mechanical properties (above).

Although gas may enter the annulus by a number of distinct mechanisms, the prerequisites for gas entry are similar. There must be a driving force to initiate the flow of gas, and space within the cemented annulus for the gas to occupy. The driving force comes when pressure in the annulus adjacent to a gas zone falls below the formation gas pressure. Space for the gas to occupy may be within the cement medium or adjacent to it.

To understand how, and under what circumstances, gas entry occurs, a review of the main mechanisms, including cement hydration and resultant pressure decline, follows. First, however, no cementing article is complete without emphasizing that good cementing practices are vital. To effectively cement gas-bearing formations the central pillars of good practice—density control, mud removal and slurry design—are critical, and here is why.

**Density: Controlling the driving force—**
Gas can invade and migrate within the cement sheath only if formation pressure is higher than hydrostatic pressure at the borehole wall. Therefore, as a primary requirement, slurry density must be correctly designed to prevent gas flow during cement placement. However, there is a danger of losing circulation or fracturing an interval if fluid densities are too high. Also, consideration must be given to the free-fall or U-tubing phenomenon that occurs during cement jobs. Therefore, cement jobs should be designed using a placement computer simulator program to assure that the pressure at critical zones remains between the pore and fracture pressures during and immediately after the cement job.

Any density errors made while mixing a slurry on surface may induce large changes in critical slurry properties, such as rheology and setting time. Inconsistent mixing also results in placement of a nonuniform column of cement in the annulus that may lead to solids settling, free-water development or premature bridging in some parts of the annulus. This is why modern, process-controlled mixing systems that offer accurate density control are important.

---

3. Cement free-fall or U-tubing occurs when the weight of the slurry causes it to fall faster than it is being pumped. This must be considered when designing displacement rates and pumping schedules.
Density control are proving popular for critical cement operations (left).

A cement slurry will not transmit hydrostatic pressure forever. The transition from a liquid that controls formation pressure to an impermeable solid is not instantaneous. Consequently, there is a period during which cement loses the ability to transmit pressure. No matter how carefully a slurry has been designed to counterbalance formation pressure, it will not necessarily resist gas invasion throughout the hydration process.

**Mud removal: No easy paths for gas**—If channels of mud remain in the annulus, the lower yield stresses of drilling fluids may offer a preferential route for gas migration. Furthermore, water may be drawn from the mud channels when they come into contact with cement. This can lead to shrinkage-induced cracking of the mud, which also provides a route for gas to flow. If the mud filter cake dehydrates after the cement sets, an annulus may form at the formation-cement interface, thus providing another path for gas to migrate. For example, a 2 mm [0.08 in.] thick mud filter cake contracting by 5% will leave a void 0.1 mm [0.004 in.] wide that has a “permeability” on the order of several darcies.

**Cement slurry design: Mixing the right stuff**—Fluid-loss control is essential. Under static conditions following placement, uncontrolled fluid loss from the cement slurry into the formation contributes to volume reduction. This reduces pressure within the cement column and allows space for gas to enter.

Before the cement slurry sets, interstitial water is mobile. Therefore, some degree of fluid loss always occurs when the annular hydrostatic pressure exceeds the formation pressure. The process slows when a low-permeability filter cake forms against the formation wall, or can stop altogether when annular and formation pressures equilibrate. Once equilibrium is reached, any volume change within the cement will cause a sharp pore-pressure decline in the cement slurry or the developing matrix, and severe gas influx may be induced. Poor fluid-loss control in front of a gas-bearing zone may accelerate the decrease in cement pore pressure. It is equally important to have a cement slurry with low or zero free water, particularly in deviated wells. As cement particles settle to the low side, a continuous water channel may be formed on the upper side of the hole, creating a path for gas migration.
How Gas Gets into the Annulus

Understanding the mechanisms of gas migration is complicated by the evolution of the annular cement column with time. The slurry begins as a dense, granular suspension that fully transmits hydrostatic pressure. As the slurry gels, a two-phase material comprised of a solid network with pore fluid forms. Finally, the setting process reaches a point where the cement is for all intents and purposes an impermeable solid. After slurry placement, gas may enter through different mechanisms according to the evolution of the cement’s state, the pressures it experiences and other wellbore factors.

Cement state 1: Dense granular fluid—When pumping stops, the cement slurry in the annulus is a dense, granular fluid that transmits full hydrostatic pressure. If formation pore pressure is not greater than this hydrostatic pressure, gas cannot invade. However, almost immediately, pressure within the annulus begins to fall because of a combination of gelation, fluid loss and bulk shrinkage.

This pressure reduction is best described by the evolution of a wall shear stress (WSS) that begins to support the annular column as the cement slurry gels. In order for a stress to evolve to counteract the hydrostatic pressure, there must be a vertical or axial strain at the annulus walls. This strain is caused by the removal of material during the hydration and setting processes—primarily through fluid loss and shrinkage.

If it is assumed that WSS equals the static gel strength (SGS) of the slurry and there is sufficient axial strain, the following simplified expression can be used to describe hydrostatic pressure reduction during gelation:

\[
\Delta P = \frac{SGS}{D_h - D_c} \cdot \frac{4L}{D_h}
\]

where \(\Delta P\) = hydrostatic pressure change across column length

- SGS = static gel strength
- \(D_h\) = hole diameter
- \(D_c\) = casing outside diameter (O.D.)
- \(L\) = cement column length.

As the cement sets, static gel strength constantly increases, with the rate of increase dependent on the nature of the slurry. There is potential for gas invasion once pressure in the annulus falls below the pressure in the gas-bearing formation. Even with a mud filter cake between the formation and cement, a differential pressure of less than 1 psi may allow gas to invade. The resistance of an external filter cake to gas flow is controlled by the cake’s strength and adhesion to the rock face, which both have relatively low values for drilling fluids and neat cements.

This explains the driving force of gas invasion, however, there must also be space within the cemented annulus for gas to occupy. Space is provided by shrinkage, which occurs because the volume of the hydrated phase is generally less than that of the initial reactants. This total shrinkage is split between a bulk or external volumetric shrinkage, less than 1%, and a matrix internal contraction representing 4 to 6% by volume of cement slurry.

Permeability is a more complicated issue. Once gelation begins, a cement slurry can be considered as a pseudoporous medium as long as the stress that it must withstand from formation fluid is less than its intrinsic strength. Thus, even though only a partial structure has been formed and the cement column is not yet fully self-supporting, with regard to its flow capacities, it can be said to have permeability.

Concrete slurries display an evolving yield stress that must be overcome before gas entry and flow can occur. Depending on the state of the slurry, gas can migrate by micropercolation, bubbles or fractures. Opportunity for gas entry decreases as the cement cures. The rate and degree of yield stress development at the time of invasion will influence the form in which gas flows. Gas may enter and flow through the porosity of the gelling structure without disrupting it—micropercolation. Gas may also move by disrupting the gel structure in the form of bubbles or elongated slugs, in channels along the interfaces with the casing and formation or as bubbles which adhere to one of the surfaces of the annulus. If rising gas remains connected to the influx source it may form a plume as it moves through the cement slurry (above).

The size of gas bubbles entering the annulus is governed by the size of the cement pore throats and the surface tension between the gas and the slurry. Once bubbles have invaded the annulus, their lower density provides a driving force—buoyancy—for them to move up the annulus through any available path. Bubble flow is controlled by slurry gel strength, and is restricted to early in slurry development. When cement shear strength is greater than about 25 Pa, bubble flow ceases.

At higher yield stress values, slurry behavior changes from that of a viscous fluid to a viscoelastic fluid, and the possibility of flow by viscous fingering or viscoelastic fractures arises. The differential pressure—between

---


6. Geometry separates fingering and viscoelastic fractures. A fracture has a sharp tip; a finger has a smooth tip. This difference is determined by a fractal length scale that is associated with the fracture or finger geometry.

---

Spring 1996
annulus and formation—combines with the developing elasticity of the cement to determine the rates of deformation and internal relaxation. The relative values of these determine the transition from fingering to fracture. The transition to fracture is exacerbated if the cemented annulus contains an internal tensile stress caused by the strain of shrinkage, fluid loss or pressure fluctuations in the casing. Gas may then drive the propagation of fractures and lead to a rapidly extending gas channel. Hydrostatic pressure will continue to decline as static gel strength—and resultant wall shear stress—develop sufficiently to support the weight of the cement column. The cement has now reached its second state.

Cement state 2: A two-phase material—Once a cement column becomes fully self-supporting, it may be considered to act as a matrix of interconnected solid particles containing a fluid phase. Setting continues and hydration accelerates. Pressure, now a pore pressure, decreases further as cement hydration consumes mix water. This leads to an absolute volume reduction or shrinkage of the internal cement matrix by up to 6%. Furthermore, the majority of shrinkage occurs at this stage, leading to tangential tensile stresses in the annulus, which may assist the initiation of fractures and disrupt bonding between the cement and the casing or formation.

Internal shrinkage creates a secondary porosity in the cement composed mainly of conductive pores. At the same time, the volume of water continuously decreases due to hydration, and its ability to move within the pores is reduced by chemical and capillary forces. Shrinkage and water reduction sharply decrease the hydrostatic pressure that cement exerts on formations.

There are two essentially different mechanisms for gas invasion at this stage, depending on the strength of the solid structure and the ease with which pore fluid can be forced through the cement pores by invading gas. Early in the setting process, while the cement still has a weak solid structure, the possibility of creating fingers or viscoelastic fractures remains. Later, the solid network becomes sufficiently stiff and strong to withstand this effect, and gas invasion and subsequent flow are limited by the impermeability of the solid network to pore fluids. Now, the flow of gas through a channel of connected, fluid-filled cement pores is limited by the flow of that pore fluid as it is displaced through the porous structure and by the connectivity of the channel.

Once gas has invaded the porous structure of the cement, it may rise due to buoyancy forces. Alternatively, if the invading gas remains connected through the cement pore space to the gas-bearing formation, the higher pressure in the formation may force gas farther into the annulus. If gas pressure is higher than the minimum compressive stress in the cement and the permeability is too low to allow significant flow, then the cement may fracture. However, this is likely to occur only where residual tensile stresses in the annulus are sufficiently high to allow cracks to open under the influence of the gas pressure.

During the latter stages of this phase, there is a significant and rapid decrease in pore pressure as water is further consumed by hydration. If this occurs while the pore structure is still interconnected, gas may invade and flow rapidly through this pore space (next page). Gas flow may also displace fluid remaining in the pores and prevent complete hydration that would eventually block pore spaces with reaction products.

Cement state 3: An elastic solid—Once hydration is complete, cement becomes an elastic and brittle material that is isotropic, homogeneous and essentially impermeable. In most cases, gas can no longer migrate within the cement matrix and can flow only through interfacial channels or where there has been mechanical failure of the cement.
Regardless of the cement system used, gas can still migrate at the cement-formation or cement-casing interfaces if a microannulus develops, or along paths of weakness where the bond strength is reduced. Both shear and hydraulic bond strengths vary as a function of the same external parameters. Bond strengths increase with effective mud removal, and with water-wet rather than oil-wet surfaces.

Researchers at Schlumberger Cambridge Research (SCR) have characterized the nature of hydraulic bonding by measuring shear bond stress and interfacial permeability. This work showed that lower chemical shrinkage and higher cement deformability promote better bonding. In addition, SCR researchers found that bonding is not influenced by the cement's compressive strength.

Although cement shrinkage leaves partially unbonded areas, it does not by itself lead to the development of a microannulus. Development of a true microannulus more likely results from stress imbalances at the interfaces due to:

- thermal stresses— from cement hydration, steam or cold fluid injection
- hydraulic pressure stresses—caused by fluid density changes in the casing, communication tests, casing pressure tests, squeeze pressure or stimulation treatment pressures
- mechanical stresses—caused by drillpipe and other tubulars banging in the casing.

The second potential conduit for gas in set cement is the mechanical failure of the cement sheath due to propagation of radial fractures or cracks across the annulus. These cracks may be due to shrinkage-induced stresses, thermal expansion and contraction of the casing, and pressure fluctuations within the casing.

Radial expansion at the cement-casing interface, due to increased pressure in the casing, creates a stress that compresses the cement radially and eventually induces tensile tangential stress in the cement. When

![Slurry Permeability](image1)

![Slurry Pore Pressure](image2)

![Slurry Temperature](image3)

Changes in slurry permeability, pore pressure and temperature versus hydration time. These graphs show that cement pore structure is still interconnected when pore pressure begins to decrease rapidly. In this Dykerhoff class G plus 1% calcium chloride slurry, pore pressure begins to drop after about 5 hours, just before the peak temperature of hydration is reached. When cement pore pressure drops below formation gas pressure, it is likely that cement permeability will still be in the milidarcy range, potentially allowing significant gas flow by micropercolation.

8. A limited exception to this may occur in the case of cement systems with high water-cement ratios, resulting in fairly high innate permeabilities (0.5 to 5 md). However, these are exceptional and not considered significant among those cements generally placed when a potential gas migration problem is thought to exist.
9. Deformability is the reciprocal of elastic modulus.
this tangential stress reaches the tensile strength of the cement—which may be close to zero if shrinkage-induced cracks already exist—a crack initiates at the casing-cement interface (below).

Cracks change the stress distribution in the cement sheath. Once a crack is initiated, tangential stress in the cracked section is reduced to zero. Conversely, stress in adjacent uncracked cement eventually increases because of stress redistribution. This process helps the crack propagate radially outward and eventually reach the cement-formation interface. Stress is now fully transferred to the cement-formation interface. If this cracking occurs over a significant axial distance, a channel is formed through which gas can readily flow.

Long-term cement durability is important if a well is to remain safe throughout its life-time. During its active life, a cemented annulus may be subjected to wide variations of temperature and stress from pressure testing, workover operations and variations in producing conditions.

However, field surveys on gas storage wells—which endure some of the most extreme swings in conditions—determined that annular gas leakage occurs early, within the first few cyclic fluctuations in temperature and pressure, rather than over a long period. This implies that leakage occurs due to failure induced by static loads rather than long-term, low-cycle fatigue crack growth. Deeper and higher-pressure wells showed the greatest tendency to leak.11

The propensity of a particular cement to crack and for that crack to propagate has often been equated with compressive strength. In fact, work carried out at SCR shows that a property termed toughness determines the extent to which a cement slurry fractures under stress. Toughness is generally described in terms of the ability of a material to resist the initiation and subsequent propagation of a fracture. However, the situation is somewhat more complicated, since initiation and propagation of fractures are controlled by physical phenomena that differ, depending on the material’s structure (see “Compressive Strength Versus Toughness: A Brief Overview,” next page).

Using Theory to Define Best Practice Over the years, a number of solutions to gas migration have been proposed by the industry. Theoretical understanding helps to explain how these solutions work—and their limitations.

Physical techniques—A number of physical techniques are available to combat gas entry. Annular pressure can be applied at surface to keep formation gas from entering, and external casing packers (ECPs) can be employed to mechanically seal off the annulus at intervals and prevent gas migration. Each of these techniques may sometimes be valid, but well conditions often limit their application. Annular pressure may be restricted by the risk of inducing lost circulation in weak zones and, once the cement starts to set, surface pressure is not transmit-

The compressive strength of a material describes the stress at which a material fails when a compressive load is applied (top right). When a compressive load is applied to a sample of brittle, elastic material such as cement, stress generally increases linearly with strain (displacement) until small microcracks and flaws in the sample begin to grow.

This is a progressive mechanism and manifests itself on the stress-strain plot by the change from linear proportionality between stress and strain to a softening section of the curve near the failure point. Once the cracks coalesce and reach a critical size, the sample will fracture via a complicated mechanism, which is determined by the boundary stress conditions and geometry of the sample.

Compare this with a description of cement toughness. Simplistically, toughness describes the property of the material to resist the initiation and propagation of a crack in a particular orientation. Fracture toughness is quantitatively defined as the energy required to propagate a fracture of unit width by unit length.

Without considering mathematical details, a reasonable indication of toughness for similar materials is given by the area (A) under the stress-strain curve to the failure point. This area varies according to the toughness of the material being tested.

For example, consider two materials X and Y that have the same compressive strength. The material X has a much smaller strain to failure than material Y, which contains latex. Therefore, material Y can deform further and absorb more energy before it fractures. Material Y is tougher than material X.

Data like these were gathered at Schlumberger Cambridge Research using three-point bend test equipment (right). The cement sample is placed on two lower static knife edges and the upper moveable knife edge is moved downward until the cement fails. The equipment is designed so that the sample always fails in tension. Strain (displacement) and load (stress) are recorded using computerized data recording systems.

1. The situation is somewhat more complicated, since initiation and propagation of fractures are controlled by physical phenomena that differ depending on a material's structure.
the size of bubbles that enter, slowing their subsequent rise—even when the yield stress of the cement is relatively low.

Polymer latex additives are effective in resisting gas migration. A latex is an aqueous dispersion of solid polymer particles, including surfactants and protective colloids that impart stability to the dispersion. In the past, the gas-blocking mechanism of latex additives was attributed to a capability to form films—when latex particles come in contact with a gas or when their concentration exceeds a given threshold value, they coalesce to form an impermeable polymer barrier to gas.

However, new work has revealed that latex particles are also able to block gas when the cement slurry has developed some structure or some compressive strength. This demonstrates that the primary effect of latex particles is matrix permeability reduction by plugging spaces between cement particles, rather than by the formation of an impermeable plastic film. Due to its smaller size and lower density compared to cement particles, latex reduces cement slurry porosity, improves fluid-loss control, decreases relative permeability to water and limits gas migration.

After some structure or compressive strength develops, the primary latex gas-blocking mechanism is matrix permeability reduction by plugging of pore spaces between cement grains. Because of its small size and lower density compared to cement particles, latex reduces cement slurry porosity, improves fluid-loss control, decreases relative permeability to water and limits gas migration. (above) Latex particles reduce slurry porosity by 10 to 15%, depending on slurry density and composition (see “A Robust System to Cement Gas-Bearing Formations,” next page).12 Latex additives also affect the properties of the cement when it is set (see Tough cements, page 46).

The addition of other types of fine fillers with particle size in the micron range may decrease permeability throughout the rapid hydration stage by quickly decreasing pore continuity. For example, if 30% by weight of these fine particles is added to a slurry with a water-cement ratio of 0.45, the pores become discontinuous about 30% more quickly. In addition to latex additives, silica fume and microsilica have been used successfully in the field.

Right-angle-set cements—Right-angle-set (RAS) cement slurries are well-dispersed systems that show no progressive gelation tendency, yet set rapidly. Before setting, RAS systems maintain a full hydrostatic head on gas zones, developing a low-permeability matrix with sufficient speed to prevent significant gas migration.

It is important to differentiate between true RAS systems and cement slurries that only build a gel strength. The high-gel-strength systems quickly revert to a water hydrostatic gradient and, since their gel strength development is not related to actual setting, permeability can remain high for a considerable time. This may allow gas to enter the cement matrix many hours before the cement sets. On the other hand, RAS cement systems rapidly build consistency as a direct result of the setting process.13

Surfactants—Surfactants may be included in cement slurries and preflushes. Under the right circumstances, they entrain invading gas downhole and create a stable foam. This foam offers significant resistance to flow, limiting upward gas migration.14

Compressible cements—Compressible cements are sometimes used in an attempt to maintain the cement pore pressure above formation gas pressure. These slurries fall into two main categories: foamed cements and in-situ gas generators.

Foamed cements work by expanding to occupy the reduction in slurry volume due to fluid loss or chemical contraction. This

---

The “ideal” slurry properties required to successfully withstand gas invasion include:

- favorable rheology to facilitate efficient placement
- no gel strength development to maintain hydrostatic balance
- rapid transition to set
- low shrinkage to minimize gas entry
- low fluid loss
- low permeability as the slurry sets
- toughness to absorb stress changes
- good bonding to avoid microannuli.

The Dowell GASBLOK gas migration control cement system combines specific additives and strict adherence to good cementing practices, including spacers and washes, and casing centralization. It has a wide range of applications and has had excellent success. The system is based on using a well-dispersed, thin, nongelling slurry with fluid-loss control. The slurry is also impermeable to gas in the cement matrix due to plugging of pore throats during the setting period (above).

In addition to reducing permeability in the presence of gas, GASBLOK slurries exhibit many other desirable properties. The main advantages are ease of design and consistent properties over a wide range of temperatures.

The lubricating action of the aqueous dispersion of the latex beads creates low-viscosity slurries. These thin slurries are beneficial for effective mud removal, since the friction pressure during placement is reduced and the critical rate for turbulent flow will be lower. If turbulent flow cannot be achieved and an effective laminar regime is chosen, it is necessary to increase the value of the rheological parameters to satisfy WELLCLEAN mud removal service criteria. Viscosification of a GASBLOK slurry is easily achieved.

Fluid loss is minimal—50 ml/30 min at the recommended latex concentration—due to the plugging of pore throats in the cement filter cake by latex particles and improved dispersion of cement grains. Setting and thickening times are straightforward and slurries exhibit rapid sets. There is no premature gelation of the slurry when the GASBLOK additive is well stabilized. The slurry remains thin until final setting. The criterion used is that the slurry should remain below 30 units of consistency for at least 70% of the thickening time. Above 250°F [121°C] bottomhole circulating temperature, a right-angle set should be easily obtained.

The tendencies for free-water development and settling of GASBLOK slurries are minimal. The formation of water channels or pockets (especially in deviated wells) is therefore greatly reduced and slurry density variations, with resulting changes in slurry properties, are avoided.

Once set, a cement must also possess good mechanical properties to withstand thermal and mechanical stresses. Poor shear bond strength may lead to formation of microannuli through which gas can migrate. GASBLOK slurries display increased tensile strength, reduced drying shrinkage, increased fracture toughness and improved adhesion or bond strength. Dowell latex slurries demonstrate all of the necessary properties to keep gas at bay. In certain cases, other cement systems used together with proper placement techniques have been as successful as, or even better than, latex in achieving particular individual properties, but none demonstrate the same complete range of desirable properties as the GASBLOK slurries.

**Comparison of cement permeabilities.** The GASBLOK slurry retains lower permeability throughout the hydration process. Compared to a neat cement slurry, after about 40 hours of hydration, it has permeability that is an order of magnitude lower.
expansion maintains a higher pore pressure in the slurry for longer than would have been the case with incompressible slurries. Foamed cement may be limited by depth because in deeper, higher pressure wells more gas is needed than is available in the cement to compensate for the chemical contraction.

In-situ gas generators are designed to maintain cement pore pressure by chemical reactions that produce gas downhole. The gas produced may be hydrogen or nitrogen depending upon the technique used.\(^{15}\)

The principal criticism of these systems—other than concerns about the safety of those that generate hydrogen—is the inability of a gas at typical downhole pressure to achieve the 4 to 6% volumetric expansion necessary to maintain pore pressure. The volume of gas required to offset chemical shrinkage alone would be excessive at high pressure. Also, in unstabilized gas-generating systems, individual gas bubbles may coalesce and begin migrating, creating channels for formation gas to follow.

Expansive cements—Fractures occur in gelled cement according to the distribution of stress in the annulus. Eliminating this stress—and avoiding fractures—limits gas invasion. Tensile stresses build up in the gel if annular volume increases or cement volume decreases. Thus, designing cement slurries with low shrinkage and controlled fluid loss during the gelation stage, and avoiding excessive pressure fluctuations in the casing are important in preventing fractures.

Designing cement slurries that expand as they set takes this one step further. The two principal techniques for inducing expansion in oilwell cements are gas generation and crystal growth. The gas-generating technique operates on the same principle as that used for compressible cements, except that the concentration of gas-generating material is reduced. Also, expansion can occur only after the cement develops significant structural strength.

The most common way of inducing expansion is to encourage the development of ettringite—a highly hydrated form of calcium sulfoaluminate—during the hydration reaction. This is often achieved by adding gypsum or plaster of Paris to the cement powder. Ettringite increases the growth of certain expansive crystalline species within the set cement matrix. Bulk volumetric expansion is generally less than one percent.

Alternatively, oxides of certain alkaline earth metals may be added to achieve expansion. An advantage of these is that the expansion occurs above 170°F [77°C], a temperature at which ettringite is unstable.

There is little doubt that controlled cement expansion by crystalline growth can help seal small gaps between the cement sheath and the casing or formation, but it is unlikely to be effective in sealing large channels created by gas migration. Much of the expansion takes place after gas flow has been initiated and the size of the created channels is simply too large. Also, these cements undergo a bulk expansion, but still exhibit a net chemical contraction and experience the same hydrostatic and pore pressure decreases as nonexpansive cements.

Thixotropic cements—During cementation factor, mud-removal factor, hydrostatic conditions, gas-zone permeability and mud-spacer efficiency within the cement paste or binder are important in preventing fractures.

There are two ways to induce thixotropic behavior in a cement slurry. The first involves creation of a microcrystalline network of mineral hydrates throughout the slurry by adding a small amount of plaster, bentonite or silicate materials. This friable and temporary microstructure supports the bulk of cement solids from an early stage in the slurry’s life. The second technique employs polymers (dissolved or dispersed in the interstitial water), which are crosslinked to create a self-supporting viscous gel by chemical reaction.

The transmitted hydrostatic pressure of thixotropic systems should revert to the gradient of the interstitial water and remain as such until the setting period begins. How-
Qualitative gas-migration prediction. The GASRULE slide-rule-based method of working out the optimal cementing solution has been refined and incorporated into a quantitative design approach.

Gas Migration Mechanisms and Controlling Factors

<table>
<thead>
<tr>
<th>State</th>
<th>Mechanism</th>
<th>Limiting parameters</th>
<th>Potential gas flow rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Viscoelastic fluid</td>
<td>Bubble flow</td>
<td>Yield stress, gap width</td>
<td>$10^{-3}$ m^3/sec</td>
</tr>
<tr>
<td></td>
<td>Tube flow</td>
<td>Yield stress, gap width</td>
<td>$10^{-3}$ m^3/sec</td>
</tr>
<tr>
<td></td>
<td>Viscous fingering</td>
<td>Plastic viscosity, viscosity ratio</td>
<td>$10^{-3}$ m^3/sec</td>
</tr>
<tr>
<td></td>
<td>Fracture</td>
<td>Elasticity, stress in annulus, Relaxation Time</td>
<td>$10^{-3}$ m^3/sec</td>
</tr>
<tr>
<td>Porous solid</td>
<td>Fingering</td>
<td>Fluid viscosity, Elasticity, darcy drag, stress in cement, elasticity</td>
<td>$10^{-3}$ m^3/sec</td>
</tr>
<tr>
<td></td>
<td>Fracture</td>
<td>Permeability, darcy drag, capillary pressure</td>
<td>$10^{-3}$ m^3/sec</td>
</tr>
<tr>
<td>Elastic solid</td>
<td>Fracture</td>
<td>Fracture toughness, interfacial toughness, stress state</td>
<td>$10^{-2}$ m^3/sec</td>
</tr>
</tbody>
</table>

19. The prediction methodology outlined is based on experiment, engineering and statistical analysis. This approach assumes flow through the evolving cement matrix. The model cannot predict the appearance of gas flow weeks or months after the cement job.

Three developments have helped refine the GASRULE approach. First, in 1990, the empirical mud-removal factor was replaced with a more complete approach, based on the Dowell WELLCLEAN mud removal technology—which helps choose washes, spacers and slurry types, while indicating whether a turbulent or laminar displacement regime is the most favorable. Second, the hydrostatic factor used in the GASRULE system has been replaced by a more rigorous postplacement analysis.

The third development marks a major advance. A quantitative design approach has now been incorporated in the new CemCADE cement job computer-aided...
design and evaluation software (right). Today, the CemCADE gas-migration module assists in design and assesses alternative solutions. This methodology is a considerable improvement over the GASRULE approach, but it does retain four similar design factors: formation factor, mud-removal factor, postplacement factor and slurry-performance factor.

**Formation factor**—Analysis begins with characterizing all possible gas-bearing formations in terms of position, height, pressure and permeability. An accurate description of pore pressure versus depth is required to optimize hydrostatic parameters. Good descriptions of the pore pressure of other permeable layers and the fracture gradient are also required. The formation factor, indicating the risk of gas flow, is calculated from these formation parameters.

The more information about the formation that is available, the greater likelihood of a good design. Trying to understand the gas migration problem is quite difficult using only an average pore-pressure gradient for the entire openhole section.

**Mud-removal factor**—As mentioned, a primary goal when cementing across a gas zone is optimum mud removal. The correct application of WELLCLEAN technology is mandatory for gas-migration control. For practical purposes, good zonal isolation over a 600-ft [180-m] section above the top of a gas zone should be achieved. In the gas-migration module, information about several factors is required to determine the quality of mud removal, including:

- Mud-circulation factor—an estimate of whether enough of the mud in the well is in circulation prior to cement placement.
- WELLCLEAN factor—the factor chosen is either the turbulent or laminar flow result for a given simulation, whichever is appropriate for the well conditions and delivers the required mud removal. Time of turbulence across the zone is calculated, along with effective volume of spacer to displace the mud in laminar flow, and effective volume of cement to displace the spacer in laminar flow, as estimated from the U-tube simulation.
Pipe-movement factor—assigns a positive value for pipe movement, which aids in breaking the gel strength of the mud and makes it easier to remove. This factor depends on whether reciprocation, rotation or both are used to enhance mud mobilization.

Bottom-plug factor—depends on the number of bottom plugs used to reduce the degree of contamination occurring as fluids are circulated.

Fluids-compatibility factor—relates to possible chemical interaction between various fluids.

The final mud-removal factor is then computed by summing these five factors—the greater the final value, the better the anticipated result.

Postplacement factor—Postplacement analysis is used to evaluate the severity of a potential gas migration problem and to quantify the influence of simple solutions such as applying annular pressure. As previously discussed, gas migration is generally caused by a loss of hydrostatic pressure. First-level understanding of this may be derived from gelation alone.

To characterize gelation, the notion of wall shear stress (WSS) has been introduced (see "How Gas Gets into the Annulus, page 39). As WSS increases, annular hydrostatic pressure fails. When hydrostatic pressure equals formation gas pressure, WSS is termed "critical" WSS (CWSS). Further increase in WSS beyond this critical value will allow gas to enter the annulus. WSS depends on parameters such as formation gas pressure, openhole diameter, and density and position of fluids. It is also sensitive to any extra annular pressure, the presence of external casing packers or techniques like two-stage cementing that may sometimes be employed to improve gas control.

CemCADE software calculates WSS and assesses how use of hydrostatic modifiers—such as ECPs—may be adjusted to maximize the critical WSS, delaying gas entry and allowing more time for cement to harden uninvaded. However, the calculation does not take into account possible fluid loss that may accelerate annular pressure decrease.

Slurry-performance factor—Once gas enters the cement column, it may migrate to a point of lower pressure. Resistance to gas depends on slurry composition. For every slurry there is a minimum wall shear stress (MWSS) above which gas can no longer migrate. The MWSS depends mainly on the chemical composition of the slurry as well as bottomhole static temperature.

For every design there is a critical range for WSS and, therefore, a critical time period during which gas can migrate in the slurry. This period extends from the time at which the slurry reaches critical WSS to the time it becomes impermeable to gas. Optimizing a design consists of reducing this time period by increasing critical WSS, decreasing MWSS or shortening the time to go from the CWSS to the MWSS.

The two parameters used by the Dowell CemCADE system to calculate the slurry-performance factor are transition time and fluid loss. The faster the slurry develops impermeability to gas, the lower the probability that gas migration will occur. The measure of the evolution of the relative permeability of a cement slurry to gas during the hydration period determines whether a cement slurry can control gas. The rate of cement-slurry permeability decline is difficult to measure. But it is possible to correlate permeability decline to the rate of change in consistency of a cement slurry during an API thickening time test—that is, the transition time.

During cement hydration, a major cause of pore-pressure loss is the loss of fluid to surrounding formations. The propensity for gas to percolate may thus be related to the fluid-loss potential of the slurry. Transition time and fluid loss have been incorporated into a single term, the slurry-performance factor.

Gas-migration factor—The formation, mud-removal, postplacement and slurry-performance factors are then linearly combined to give the final index or gas-migration factor. Evaluation of the risk associated with a given design is based on the gas-migration factor compared to a scale ranging from "very critical" to "very low" risk of migration.
From the earliest days of exploration, prospectors associated salt with oil and gas—but not always for the right reasons. In the 1920s, so many successful wells were drilled around salt domes that logging methods were tuned to identify the high-salinity water in formations overlying pay zones. By 1923, gravity and seismic methods became successful in spotting salt domes, and the industry was on its way to understanding the structural role played by salt. Today, interpreters can view and tour salt structures with the help of powerful graphics workstations (next page, top).

Salt is one of the most effective agents in nature for trapping oil and gas: as a ductile material, it can move and deform surrounding sediments, creating traps; salt is also impermeable to hydrocarbons and acts as a

Advances in seismic imaging have changed the way explorationists view salt bodies. Once seen as impenetrable barriers to geophysical probing with some flanking pay zones, many salt structures are now proving to be thin blankets shielding rich reserves. Geophysicists are developing new methods to see through salt, illuminating the reservoirs below. This new vision of subsalt is impacting E&P decisions from well planning and drilling to field delineation and development.

[Distribution of offshore salt sheets. Adapted from Ward RW, MacKay S, Greenlee SM and Dengo CA: "Imaging Sediments Under Salt: Where are We?" The Leading Edge 13, no. 8 (August 1994): 834.]

For help in preparation of this article, thanks to Mark Bogaards, Cliff Kelly and Mark Puckett, Wireline & Testing, Houston, Texas, USA; Bob Godfrey, Colin Hulme, Tore Karlsson, Jane Lam, Dominique Pajot, John Uillo and Öz Yilmaz, Geco-Prakla, Gatwick, England; George Jamieson, Geco-Prakla, Houston, Texas; and Ron Roberts, Amoco, Denver, Colorado, USA.

Passive—No Space Problem

Active—Diapir Creates Space

Reactive—Extension Creates Space

Styles of salt intrusion. When the overlying sediments offer little resistance (top), salt can rise, often dragging flanking layers up with it. If the overburden does resist, salt pressured from below (middle) can still push through, doming the overburden and creating radial faults in the process. In the case of regional extension (bottom) faulting in the rigid overburden can open the way for salt to rise. [Adapted from Jackson MPA, Vendeville BC and Schultz-Ela DD: “Salt-Related Structures in the Gulf of Mexico: A Field Guide for Geophysicists,” The Leading Edge 13, no. 8 (August 1994): 837.]

Seal. Most of the hydrocarbons in North America are trapped in salt-related structures, as are significant amounts in other oil provinces around the world (previous page). Many reservoirs in the North Sea are below salt, as are large fields in the Gulf of Suez.2

A product of seawater evaporation, salt accumulation can reach thousands of feet in thickness. Salt retains a low density of 2.1g/cm³ even after burial. However, the surrounding sediments compact and at some depth become denser than the salt—an unstable situation. If the overlying sediments offer little resistance, as is sometimes the case in the Gulf of Mexico, the salt rises, creating characteristic domes, pillows and wedges that truncate upturned sedimentary layers (right). If the overburden does resist, salt can still push through, creating faults in the process. If tectonic conditions are right, extensional faulting in the rigid overburden can open the way for salt ascent. Much of the Zechstein salt pervasive in the North Sea has been mobilized this way.

In contrast to salt’s low density is its high seismic wave velocity—4400 m/sec (14,432 ft/sec)—often more than twice that of surrounding sediments. The strong velocity contrast at the sediment-salt interface acts like an irregularly shaped lens, refracting and

Flying through a seismic interpretation. The top of a salt feature (yellow surface) has been interpreted on a seismic workstation. Also shown is a panel of seismic data (background), a reflector above the salt (brown surface), seismic velocities at vertical well locations (multicolored vertical logs) and deviated well trajectories (blue lines).
reflecting seismic energy. Early data processing techniques treated this contrast like a mirror, resulting in images that portrayed salt features as bottomless diapirs extending to the deepest level of seismic data (left). In the 1980s, seismic processing began to correctly image the steeply dipping and sometimes overhanging faces of salt where hydrocarbons could accumulate.

But in the last five years, a new image of salt has emerged. In some areas, not only is the top of salt clearly visible, but the bottom also. Geologists hypothesize that in these areas of allochthonous salt—found away from its original depositional position—conditions allow the salt, having reached vertical equilibrium, to begin flowing horizontally (above). In the Gulf of Mexico, this occurs mainly in deep water beyond the continental shelf, where sediment cover is not as thick as it is near shore (bottom left). Wells drilled through thin salt sheets have encountered oil-bearing sediments below. However, knowledge of the existence of hydrocarbons below salt is insufficient reason to start drilling. Drilling salt is risky (see “Drilling and Completions Through Salt,” page 54). The salt itself is weak and undergoes continuous deformation. Below intruded salt, sediment layers are often disrupted and overpressured. And most important, unless seismic data have been processed to image through the salt, the position of the target is unknown.

Evolution of salt intrusions. Salt walls and diapirs are initiated at instabilities on extensive salt layers. As the salt rises and then flows horizontally, the walls and diapirs change shape. Eventually some salt features become completely detached from the parent salt layer.

Evolution of salt sheets mapped in the Gulf of Mexico. Recent exploration wells correspond to wells mentioned in table (next page).
A few operators have announced significant oil discoveries beneath salt in the Gulf of Mexico, rekindling a spirit of exploration in the Gulf. Phillips Petroleum Company, in partnership with Anadarko Petroleum Corporation and Amoco Production Company, announced the first commercial Gulf of Mexico subsalt discovery with the Mahogany prospect in 1993, and attributed the success to the imaging technique called prestack depth migration. Drilled in 375 ft [114 m] of water to a depth of 16,500 ft [5030 m], the well produces from sediment layers beneath a salt sheet 3000 to 8000 ft [915 to 2439 m] thick.

Since the Mahogany find, many more wells have been drilled in the area, with other operators experiencing similar success (left). Before prestack depth migration, the success ratio in the subsalt play was around 5%. The new technique is increasing that to 25%. Depth migration is also bringing first-time details to light in some of the many North Sea reservoirs that produce from below salt, and operators plan exploration campaigns in the Red Sea using the same method.

What is this imaging technique and how does it help illuminate subsalt reservoirs? The answers are found in a review of the family of imaging methods, including prestack depth migration, that are bringing subsalt and other complex structures to light.

(continued on page 56)

---

Subsalt drilling scorecard in the Gulf of Mexico. Since the successful well drilled by Phillips and partners in 1993, subsalt exploration in the Gulf of Mexico has blossomed.

[From Taylor G: “Subsalt Returns to the Top,” AAPG EXPLORER 17, no. 2 (February 1996): 8.]

---


5. For more on subsalt imaging topics: The Leading Edge 13, no. 8 (August 1994).
Properties of salt—pseudoplastic flow under subsurface temperatures and pressures, and low permeability—that make salt bodies effective hydrocarbon traps also present unique challenges for oil and gas operators (above). Special considerations, from selecting drilling fluids and bits to implementing casing programs and cementing procedures, are required to produce long-lasting wells. Methods developed on the US Gulf Coast and in the Gulf of Suez, Egypt have improved the efficiency and reliability of drilling and completion operations in thick salt sections.¹

Unlike typical sediment sequences in which horizontal stresses are less than vertical stresses from overburden, salt is like a fluid, with stresses in all directions approximately equal to the overburden. Therefore, if borehole fluid pressure is less than in-situ salt strength, stress relaxation may significantly reduce openhole diameters. In some cases, relaxation and salt creep can cause borehole restrictions even before drilling and completion operations are finished. Undergauge boreholes can lead to stuck drillpipe, problems running casing and ultimately casing failures—ovaling, bending or collapse.

To maintain near-gauge boreholes, drilling fluids must minimize hole closure and washouts. Water- and oil-base muds with saturated and undersaturated salt concentrations, and synthetic fluids have been used to drill salt, but no single system works all the time. Water-base muds with low salt concentrations try to balance salt erosion and dissolution with creep rate to maintain hole size. However, because salt creep and dissolution change across thick salt sections, this can be problematic and hole size may vary with depth. High-salt-concentration, water-base muds dissolve enough salt to offset creep, but can become undersaturated at high temperatures and enlarge the hole. Oil and synthetic muds prevent dissolution and can be used effectively in salt, but are expensive, can leach water, gas and other mineral inclusions out of salt and may not offset creep.² Economic, easy to maintain and adaptable salt-saturated, water-base muds are often used.
Salt is weak and soft, so polycrystalline diamond and other mill-tooth insert cutters, which make hole by scraping, are used. Stronger inserts may be needed to penetrate caprock formed on the top of some salt layers by groundwater leaching of minerals. Side-cutting, eccentric or bicentered reamers above bits have been proposed to open up hole diameters that are larger than the bit and allow for some salt creep before the borehole becomes undergauge.3

After drilling into salt, heavier than expected mud weights may be needed to control salt flow. Drilling speeds vary among operators, but reasonably fast penetration rates—60 to 150 ft/hr [18 to 46 m/hr]—are required, so wells can be cased quickly. Good hole cleaning and periodic backreaming, however, should not be sacrificed just to make hole faster. Circulating a small volume of fresh water can remove salt restrictions and free stuck pipe, but care must be used to prevent washouts. Enlarged or undergauge holes make hole faster. Circulating a small volume of reaming, however, should not be sacrificed just to ensure efficient slurry placement.

Effective cement fill in the annulus between the outer casing and borehole minimizes nonuniform load effects. Long slurry thickening times may allow salt to encroach on casing before a complete set occurs, and inadequate displacement across washouts may cause unequal loading or localized bending. Adequate fluid-loss control is needed to prevent excessive loss of slurry mix water that can dissolve or weaken salt, adversely affect cement properties or cause annular bridging, loss of hydrostatic pressure and gas migration (see “Getting to the Root of Gas Migration,” page 36).

Salt-saturated cements prevent salt dissolution, but are more difficult to mix on surface and extend slurry set times (over-retardation). Freshwater and low-salt concentration slurries avoid retardation problems and are easier to handle, but long-term exposure to salt may lead to cement failures. Additives introduced in the late 1980s helped solve over-retardation and strength development problems in salt-rich slurries.5 This led to development of proprietary slurries for cementing across salt zones like the Dowell SALTBOND cement system, which provides controllable thickening times, good early compressive strengths, effective placement rheology, excellent fluid-loss control and resistance to aggressive brine attack. —MET

Stacking to enhance and focus seismic signals by summing traces reflected midway between several source-receiver pairs. Energy arrives on each seismic record at a different time, depending on the source-receiver separation, or offset. The arrival times define a hyperbola. Before the traces can be stacked, they must be shifted to align arrivals. The offset versus time relationship that describes the shifts defines the stacking velocity of that layer.

Imaging
Imaging describes the two seismic data processing steps, stacking and migration, that bring seismic reflections into focus. Stacking attempts to increase signal-to-noise ratio by summing records obtained from several seismic shots reflecting at the same point (above). Energy arrives on each trace at a different time, depending on the source-receiver separation, or offset. For a uniform-velocity layer overlying the reflector, seismic rays are straight, and the arrival times define a hyperbola. The set of traces is called a common midpoint (CMP) gather. Before the CMP gather can be stacked, the traces must be shifted to align arrivals. The offset versus time parameter that describes the shifts defines the stacking velocity of that layer. Shifting is performed for all reflections visible in the traces. The result of stacking is a single trace, taken to represent the signal that would have been recorded in a normal-incidence experiment at the midpoint of the source-receiver pairs. The basic assumption in stacking is that velocity does not vary horizontally over the extent of the gather.

The second component of imaging, migration, redistributes reflected seismic energy from its recorded position to its true position using a velocity model (right). There are many classes of migration, varying in environment of applicability from simple structures and smooth velocity variations to complex structures and rapidly varying velocities.6

The main distinctions, for the purpose of this article, are the imaging domain—either time or depth—and the order of migration in the work flow—poststack or prestack. To process any one survey, combinations of migration techniques may be used. The trend today, as complex reservoirs come under scrutiny, is to use depth rather than time and prestack instead of poststack.

In time migration, the velocity model, sometimes called the velocity field, may vary only smoothly (next page, bottom). Velocity should increase with depth, and any variations in the horizontal direction should be gradual. The output of the process is a seismic volume with time as the vertical axis. Time migration is most successful when velocities are laterally invariant or smoothly varying. It is often applicable and, hence chosen in most parts of the world.

In depth migration, the velocity model may have strong velocity contrasts vertically or horizontally. Depth migration is suited for environments in which velocities change abruptly, often the case with complex structures such as steep dips, faults, folds, salt intrusions and truncated layers. The output volume has depth as the vertical axis. Depth migration, though often appropriate, is still rarely done because of the difficulty in constructing an accurate velocity model.

Poststack migration is migration applied after the seismic traces have been stacked. Stacking enhances the seismic signal, and also reduces by an order of magnitude the number of traces that comprise the stacked seismic volume, so migration poststack is roughly 100 times faster than prestack. For poststack migration to be effective, the assumptions made in stacking must be valid. The amplitude of the stacked trace must represent that of the normal-incidence trace and reflected arrivals must be approximately hyperbolic (next page, top). These assumptions are valid only when the structure is simple. Otherwise prestack migration is more suitable.

Poststack migration is run before stacking, and can handle the most complex structures
The effects of velocity variations on raytracing and common midpoint (CMP) assumptions. In a flat model with simple structures and velocities (top left), raypaths are straight and wavefronts are spherical. Arrival times on seismic records can be fit with a hyperbola (bottom left). In such a case, the CMP and reflection point would be coincident. Inserting a salt wedge over the flat reflector (top right) gives rise to bent raypaths. The arrivals do not have a hyperbolic shape on seismic records (bottom right). In this case, the CMP would not be coincident with the reflection point. Also visible in the salt case are multiples—arrivals from multiply reflected waves—that present additional processing problems. These waveforms and traces were created with 2D acoustic finite-difference modeling.

- Simple velocities + simple structure = poststack time migration
- Simple velocities + complex structure = prestack time migration
- Complex velocities + simple structure = poststack depth migration
- Complex velocities + complex structure = prestack depth migration

Velocity models for four migration classes: time, depth, poststack and prestack. Poststack models are on the left, prestack on the right. Time-based models are on the top, depth-based on the bottom. In time migration, the velocity model may vary only smoothly or monotonically—always increasing with depth. Depth migration is required for more complex velocity models. Poststack migration works with models of low complexity, while prestack migration can handle the most complex models.
and velocity fields. With the amount of data in modern 3D surveys, the main constraints on this method are the time and skill needed to construct velocity models and the computing power required for reasonable processing turnaround time.

Imaging a seismic volume containing a salt body is unlike traditional processing, in which thousands of tapes are sent off to a processing group that sends back a finished product, ready for interpretation. Subsalt imaging requires several iterations of migration and interpretation. The process is a complex interplay of many steps (left). Some of the steps, such as the migrations, are run as batch input to mainframe or massively parallel processor (MPP) computers. Others, such as velocity modeling and layer boundary interpretation, require interactive workstations.

Different operators and service companies may have variants of these methods, but the general processing flow is the same. The first step is to build an initial model of the velocity in the overburden—the velocities of layers overlying the salt. In the North Sea, several major velocity contrasts may overlie the salt. Velocity estimates can come from ray-tracing-based velocity analysis on CMP gathers. If the common midpoint geometry is not suitable, such as when velocities vary horizontally, a CMP gather cannot be used. Instead, a common image point (CIP) gather is created using a prestack migration technique to assemble all the traces that image the depths below a given surface location. In the Gulf of Mexico, sediments are typically sand-shale sequences with small velocity contrasts between layers. Without strong velocity contrast, CMP-based velocity analysis is not necessary, so initial velocities are taken from stacking velocities. In both cases, velocities are checked for trends with well data such as sonic logs or borehole seismic data.

The second step uses this early velocity model to predict reflection arrival times on CMP or CIP gathers at control points. The shape of the arrival times of the shallowest major reflector is analyzed for the velocity that best flattens the times, and the velocity model is updated. This is the most time-intensive step, and requires the intervention of an expert and the versatility of an interactive velocity modeling workstation. (For a tour of the Geco-Prakla KUDOS 3D velocity model building workstation, see “Foundations in Velocity,” page 60.)
With the updated velocity model, poststack or prestack depth migration is applied, and the gathers are recomputed and checked for arrival flatness. If necessary, these few steps are iterated to obtain an accurate velocity of the topmost layer. Then the process is repeated for as many layers as are identified above the salt.

If the top of salt appears to be structurally simple based on preliminary time migration, the velocities of the overburden can be used in a poststack depth migration to image the top of salt with good precision. An example of this is the imaging of the Cavendish 3D survey in the North Sea. The velocity model indicates a smooth top of the Zechstein salt (bottom left). Encased within the Zechstein is a thin, complexly folded dolomite, called Plattendolomit, that causes strong distortion of seismic ray paths before they reach the Silverpit target. An important step in the construction of an accurate depth-velocity model was characterizing the shape of the Plattendolomit (below right). The complexity of the velocity model—high-velocity salt overlying lower-velocity sediments—suggests that depth migration is better suited for imaging than is time migration. Applying depth migration makes a dramatic difference in subsalt structure: the dip of subsalt layers, and so the locations of potential traps, changes significantly compared to the time migration results (left).

Comparing poststack time (top) to poststack depth migration (bottom) on the Cavendish survey. The complex velocity model requires depth migration to accurately image subsalt structures. Without depth migration, the dips on subsalt layers may be incorrectly imaged.

---


2. Common image point gathers are assembled by a method that has been likened to looking for a needle in a haystack. Every possible source-receiver pair in the 3D volume of interest is checked to see whether it contributes to the signal generated by the reflection at a test point in the volume.

---

Spring 1996
Before the arrival of massively parallel processor computers, migration was the stumbling block in prestack depth imaging. Now that MPPs can handle migration in reasonably short order, the construction of an accurate 3D velocity model is the most time-consuming task. The Geco-Prakla KUDOS 3D velocity model building system allows specialists in interpretive processing to construct and visualize velocity models interactively.

Velocity modeling systems developed by other service companies, such as InDepth by Western Geophysical and GeoDepth by Paradigm Geophysical, contain similar features.

A velocity model is defined by two sets of parameters—layer velocities and reflector geometries. Such models can have either time or depth as their vertical axis. Models with time as the vertical axis are relatively easy to derive from conventional time-domain processing, and are generally smooth: rays can be traced through the models with moderate bending at interfaces, so processing steps such as computing travel times through the model can be executed rapidly and nearly automatically.

In contrast, earth models in depth usually have strong horizontal and vertical velocity variations. Rays can bend sharply at interfaces and so the reflector geometry must be known very accurately. Processing must take an interpretive pause after each layer is built, precluding automation. Efficient construction of depth-based models is the aim of the KUDOS velocity modeler.

Traditional velocity modeling programs constrain models to be simple—unlike the real earth—with no abrupt terminations, pinchouts or multiple vertical values. Layers must be continuous and extend across the entire survey. The KUDOS system, by contrast, allows models to be built with any structural complexity. Graphic elements are rendered on a high-performance workstation, allowing immediate visualization—a key ability in velocity model construction and validation.

In the KUDOS system, a modeling volume is defined that has its vertical dimension in depth. Surfaces corresponding to the main geological horizons are inserted into this volume, subdividing it. Interval velocity fields are derived and assigned to each subvolume, forming a spatially variant velocity-depth model.

Layers are added to the model in an iterative sequence. At each stage the model consists of a series of layers, each with its own velocity field, and a halfspace of unknown velocity below the bottom layer. This halfspace contains the next horizon to be imaged. The velocity that will correctly image the next horizon is derived through ray-based velocity analysis (below). The velocity of the layer is mapped by interpolating velocities determined at control points (next page, bottom). The halfspace is then “flooded” with the velocity field derived for that next horizon.

The subvolume model is then exported from the KUDOS workstation as either a tessellation or

### Interactive ray-based velocity analysis

For a chosen gather (lower left panel) traces can be shifted interactively to test different interval velocities. A plot of semblance—the coherence achieved between traces shifted with a given velocity—shows the best choices for velocities (upper left). The higher the semblance, the better that velocity flattens the traces. Velocities that are too high leave arrival times drooping at long offsets (upper right). Velocities that are too low produce corrected gathers that swing up at long offsets (middle right). The correct velocities flatten arrival times across the gather (lower right).
a 3D grid, and sent with the seismic data to the computer for post- or prestack depth migration.

Tessellation involves dividing the layered velocity model into tetrahedra (above, left and right). Interval velocities are stored at each corner of every tetrahedron, and the topographies of the depth surfaces are represented by tetrahedral facets. Tessellated volumes have special properties; they are especially efficient for modeling arrival times by raytracing—for generating travel times for prestack depth migration—and they can represent realistic geologic models with structural complexity at all scales (left). The KUDOS

Tessellated Salt Body

Velocity Control Points
system can also express the velocity model as an array of evenly spaced 3D grid points. This creates a volume that may not look as complex as the tessellated volume, but has a velocity representation more suited for some migration algorithms.

Following migration, the seismic data are loaded to the interpretation workstation, where the newly imaged horizon is delineated in depth. This surface is then incorporated into the KUDOS model, forming a new base layer. The velocity field below this layer now needs to be determined, so the next iteration of velocity analysis begins.

In some areas, such as the Gulf of Mexico, the background velocity is slowly varying and layer boundaries are difficult to identify (next page, top). Instead of proceeding in steps, layer by layer, the background velocity model is built in just a few steps, each handling several layers. At selected locations, CIP gathers are analyzed for the overall velocity function that best flattens all the arrivals simultaneously. In the KUDOS system, this method is called image-based velocity analysis. The velocity function can be modified interactively and a corrected gather can be viewed (right).

Finding the velocity function that flattens all arrivals simultaneously. Common image point (CIP) gathers (top) obtained from prestack depth migration are converted from depth to time using the current velocity model and displayed twice (left and center). The interval (green) and root mean square (RMS) velocity functions (red) for this model are shown as a pair of curves on a semblance display (right). Interval velocities can be modified interactively, automatically adjusting the corresponding RMS velocity function. A new gather is then computed, and the arrival curvature can be compared to that on the reference gather (left) which remains unchanged. Other velocities can be tested (bottom). In this example, velocities higher than the reference model have been picked (green dots) and applied to the gather (center panel). The new velocities are too high, causing downward curvature to the arrivals. The original velocities remain as black dots on the screen.
If the top of salt is rough, prestack depth migration must be applied (right). Geologists surmise that such complex topographies indicate instabilities where the upward movement of the salt, once halted, has been reactivated.

Once the top of salt has been imaged, an interpreter must delineate the top of salt on an interactive seismic interpretation workstation. Then the velocity model is updated by filling the volume below the top of salt with salt velocity, assumed to be uniform. With this new model, another prestack—or poststack if overburden velocities are smooth enough—depth migration is performed, and the bottom of salt comes into focus.

An interpreter then maps the bottom of salt. Next, and similar to the first step, velocities of the sedimentary layers below the salt are estimated. These are first approximated by the velocities of layers at the same depth but outside the canopy of salt. Then a prestack depth migration is run and sets of gathers are checked for flat arrivals. The velocity model is updated at these control points until all control points show flat arrivals on CIP gathers. Then the velocities are interpolated between control points and the full-volume velocity model is complete.

The final step is to run a prestack depth migration using the full-volume velocity model. Then individual cuts through the migrated data volume can be displayed for further interpretation. With the vertical axis in depth, locations of interpreted features can be communicated directly to engineers to guide drilling and well location decisions.

This set of techniques was used to image the salt and subsalt layers in a survey for Amoco in the southern North Sea gas basin. Layers were interpreted on the Charisma seismic interpretation system, and their velocities were modeled on the KUDOS workstation. The target layers were the Rotliegendes and Westphalian sands below...
the Zechstein salt. Comparison of poststack and prestack depth migration shows the greater clarity of the prestack method in focusing the top and bottom salt reflections (above). The prestack depth migration shows a more sharply focused reflection off the base of salt and more coherently imaged subsalt strata than does the poststack migration, paving the way for more confident interpretation of subsalt layers.

Algorithms for carrying out these classes of migration have been known for some time. But only in the past few years has computer power grown sufficiently to allow commercially acceptable turnaround for prestack depth migration. Massively parallel processors have brought the elapsed time required to process a “typical” prestack depth migration down to one month—a tenfold improvement. In this case, typical means an output volume of two to three offshore US blocks at 9 sq mile [23 km²] each. Specialists estimate that creating an accurate velocity model takes about a week for each layer in the model. Velocities must be accurate to within a couple percent to be useful for guiding subsalt drilling.

Much work remains if subsalt reservoirs are to be understood as fully as other, more accessible fields. In general, even the most carefully migrated subsalt images fail to exhibit the same signal quality as sections imaged in the absence of salt. Up to now, nearly all subsalt features drilled and labeled commercial successes have been identified by structure rather than by amplitude or other waveform attributes routinely tracked by interpreters exploring above salt.

Another seismic technique, the borehole seismic survey, offers subsalt information unobtainable by other means. These surveys, with receivers in the borehole, can measure subsalt layer velocities with high accuracy, map reflector locations and measure reflection amplitudes at the subsalt reflectors. Some operators are using borehole seismic survey results to update velocity models for reprocessing prestack depth migrations.

An advance anticipated in the future is the measurement of sonic velocities while drilling, which can be related to seismic layer velocities. Operators may be willing to update seismic velocity models and reprocess 3D surveys to get a clearer image before drilling deeper.

The future of subsalt exploration and development promises as many technical challenges as in the past. And beyond salt, the same techniques hold the power to image other complex features such as overthrust faults, reefs, recumbent folds and sediments below high-velocity carbonates.

—LS

9. Western PG and Ball GJ, reference 2.
10. The Geoco-Prakla processing megacenter in Houston, Texas, USA relies on a Connection Machine CM-5 with a 400-GBYTE disk and 512 processing nodes, providing 64 Gigaflops of peak processing power.