

From Mud to Cement—Building Gas Wells

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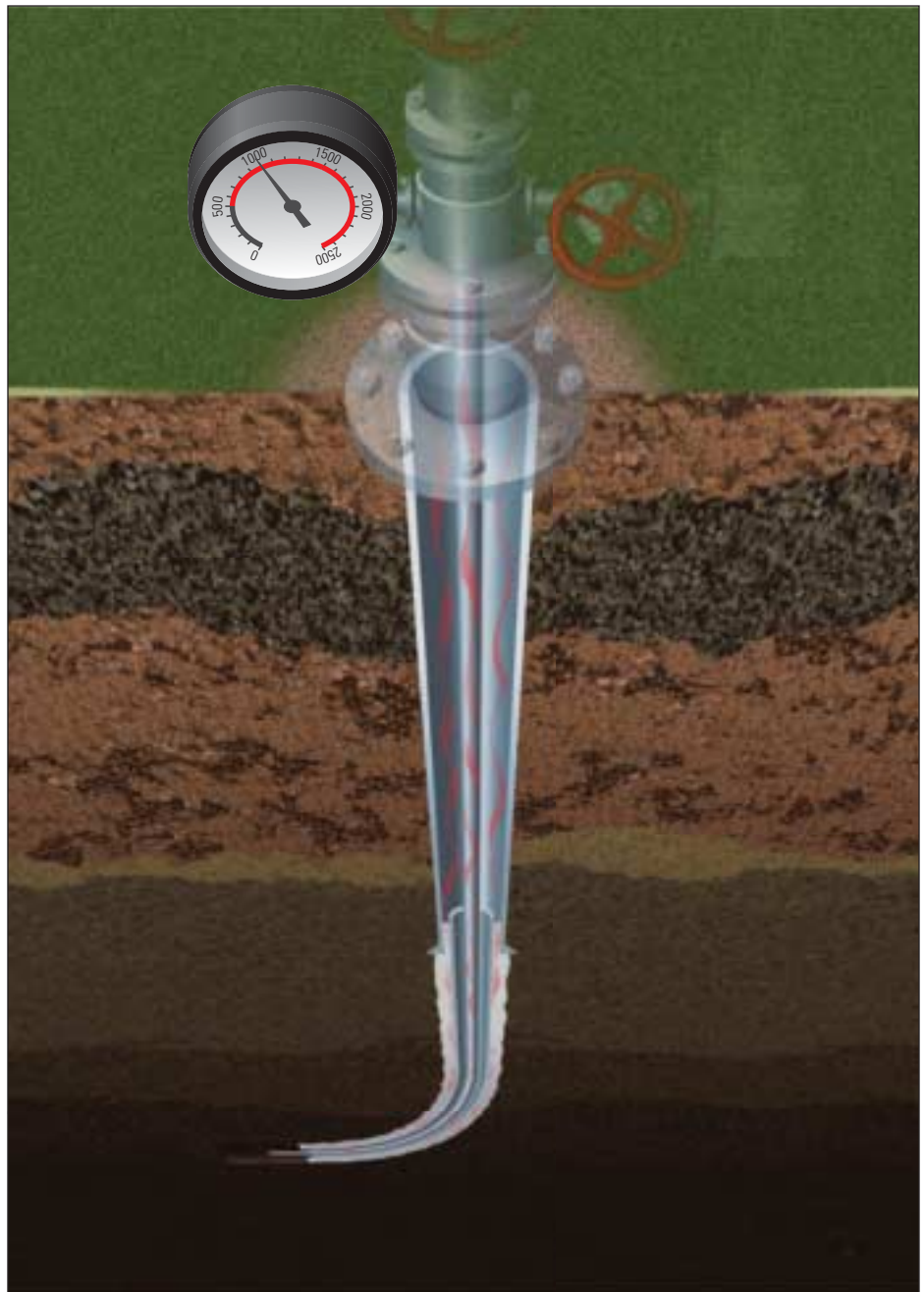
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As demand for natural gas increases, wellbore construction across gas-bearing formations takes center stage. With few cost-effective remedial measures available, prevention of annular gas flow and sustained casing pressure is key to drilling and completing long-lasting gas wells.



The science of constructing gas wells is thousands of years old. Legend has it that the Chinese dug the first natural gas well before 200 BC and transported the gas through bamboo pipelines.¹ Subsequent well-construction history is unclear until 1821, the year of the first US well drilled specifically for natural gas.² This well, in Fredonia, New York, USA, reached a depth of 27 ft [8.2 m] and produced enough gas to light dozens of burners at a nearby inn. Eventually the well was deepened and produced enough gas to provide lighting for the whole town of Fredonia. By this time, well-casing technology in the form of hollowed-out wooden logs had been developed for salt dome drilling, but it is not known whether such casing was used in the gas wells drilled during this era. In all likelihood, these first gas wells were leak-prone.

During the rest of the 19th Century, natural gas became an important energy source for many communities. Techniques for locating, exploiting and transporting natural gas to our homes and industries have had huge advances since the early days.

Despite these advances, many of today's wells are at risk. Failure to isolate sources of hydrocarbon either early in the well-construction process or long after production begins has resulted in abnormally pressured casing strings and leaks of gas into zones that would otherwise not be gas-bearing.

Abnormal pressure at the surface may often be easy to detect, although the source or root cause may be difficult to determine. Tubing and casing leaks, poor drilling and displacement practices, improper cement selection and design, and production cycling may all be factors in the development of gas leaks.

Planning for gas by acknowledging the interdependencies of various well-construction processes is critical to building gas wells for the future. This article focuses on an early phase in the gas journey—constructing the gas well. Case studies from South America, the Irish Sea, Asia and the Middle East demonstrate effective methods for selecting drilling muds, displacing mud before cementing, and constructing long-lasting wells with high-integrity cement.

Wells at Risk

Since the earliest gas wells, uncontrolled migration of hydrocarbons to the surface has challenged the oil and gas industry. Gas migration, also called annular flow, can lead to sustained casing pressure (SCP), sometimes called sustained annular pressure (SAP). Sustained casing pressure can be characterized

as the development of annular pressure at the surface that can be bled to zero, but then builds again. The presence of SCP indicates that there is communication to the annulus from a sustainable pressure source because of inadequate zonal isolation. Annular flow and SCP are significant problems affecting wells in many hydrocarbon-producing regions of the world.³

In the Gulf of Mexico, there are approximately 15,500 producing, shut-in and temporarily abandoned wells in the outer continental shelf (OCS) area.⁴ United States Minerals Management Service (MMS) data show that 6692 of these wells, or 43%, have reported SCP on at least one casing annulus. In this group of wells with SCP, pressure is present in 10,153 of all casing annuli: 47.1% of the annuli are in production strings, 26.2% are in surface casing, 16.3% are in intermediate strings, and 10.4% are in conductor pipe.

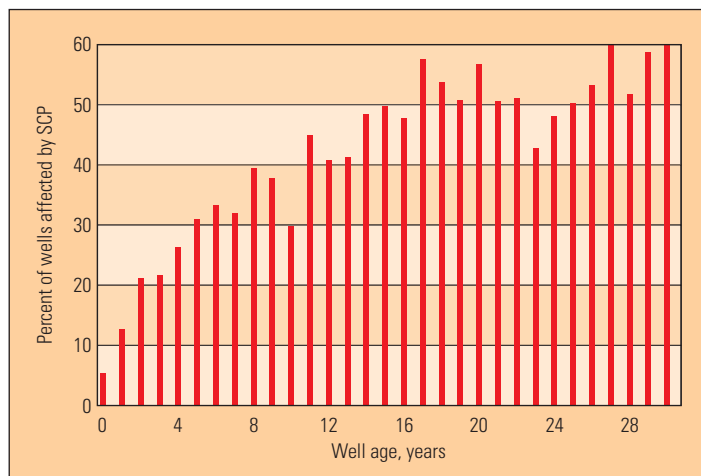
The presence of SCP appears to be related to well age; older wells are generally more likely to experience SCP. By the time a well is 15 years old, there is a 50% probability that it will have measurable SCP in one or more of its casing annuli [above]. However, SCP may be present in wells of any age.

In the Gulf of Mexico OCS area, SCP generally results from either direct communication of shallow gas-bearing sands with the surface or poor primary cementing that exposes deeper gas-bearing sands through gas migration. Most wells in the Gulf of Mexico have multiple casing strings and produce through production tubing,

making locating and repairing leaks difficult and expensive.

In Canada, SCP occurs in all types of wells—shallow gas wells in southern Alberta, heavy-oil producers in eastern Alberta and deep gas wells in the foothills of the Rocky Mountains.⁵ Most of the pressure buildup is due to gas, although, in fewer than 1% of all wells, oil and sometimes salt water also flow to surface.

Continued demand for natural gas coupled with increasingly more difficult drilling environments has heightened operator awareness worldwide to the short- and long-term implications of poor zonal isolation. Whether



^ Wells with SCP by age. Statistics from the United States Mineral Management Service (MMS) show the percentage of wells with SCP for wells in the outer continental shelf (OCS) area of the Gulf of Mexico, grouped by age of the wells. These data do not include wells in state waters or land locations.

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1. For an overview of natural gas history: <http://r0.uncad.org/infocomm/anglais/gas/characteristics.htm> (accessed August 20, 2003). <http://www.naturalgas.org/overview/history.asp> (accessed August 20, 2003).
2. For a chronology of oil- and gas-well drilling in Pennsylvania: <http://www.dep.state.pa.us/dep/deputate/minres/reclaimPa/interestingfacts/chronologyofoilandgas> (accessed August 20, 2003).
3. Frigaard IA and Pelipenko S: "Effective and Ineffective Strategies for Mud Removal and Cement Slurry Design," paper SPE 80999, presented at the SPE Latin American and Caribbean Petroleum Engineering Conference, Port-of -Spain, Trinidad, West Indies, April 27–30, 2003.
4. United States Minerals Management Service statistics: <http://www.gomr.mms.gov> (accessed August 21, 2003).
5. Alberta Energy and Utilities Board: <http://www.eub.gov.ab.ca> (accessed August 15, 2003).

constructing a gas well, an oil well, or both, long-term, durable zonal isolation is key to minimizing problems associated with annular gas flow and SCP development.⁵

Identifying Causes of Gas Migration

Annular gas may originate from a pay zone or from noncommercial, gas-bearing formations.⁷ Some of the most hazardous gas flows have originated from unrecognized gas behind conductor, surface or intermediate casing. Typically, gas flow that occurs immediately after cementing or before the cement is set is referred to as annular gas flow, or annular gas migration. This flow is generally massive and can be interzonal, charging lower-pressured formations, or can flow to

the surface and require well-control procedures. Flow to surface occurring later in the life of the well is known as SCP. Later flow also can be from gas-bearing formations to formations of lower pressure, generally at shallower depths.

Determining the precise source of annular flow or sustained casing pressure is often difficult, although likely causes can be divided into four primary categories: tubing and casing leaks, poor mud displacement, improper cement-slurry design and damage to primary cement after setting [below].

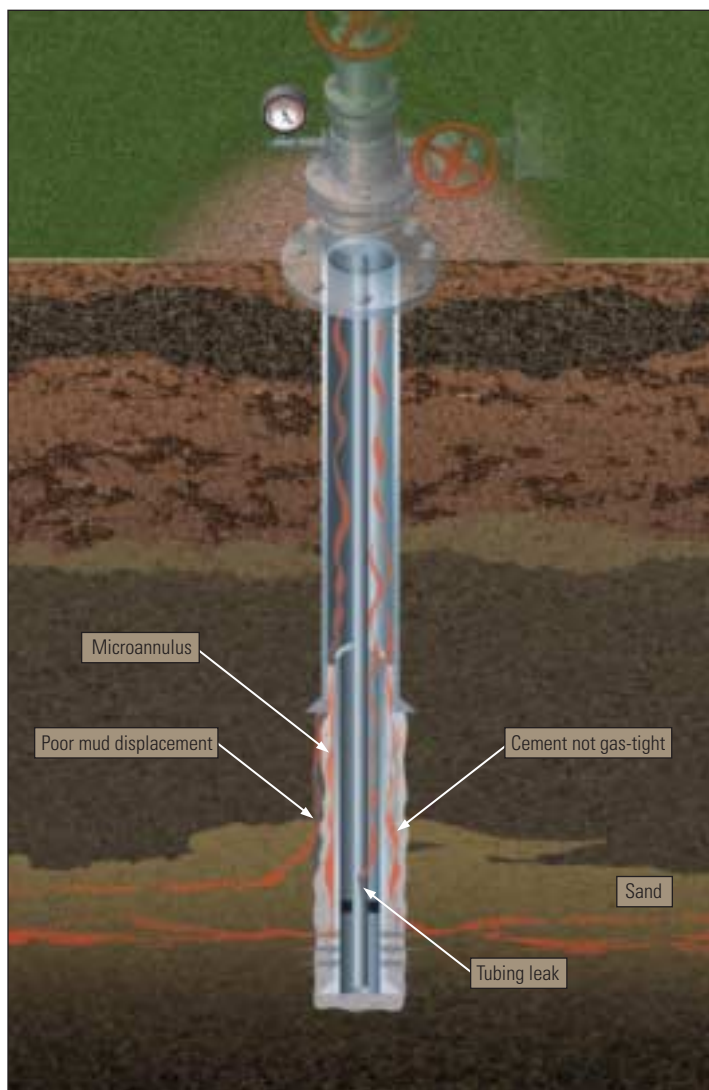
Tubing and casing leaks—Production tubing failures may present the most serious SCP problem.⁸ Leaks can result from poor thread connection, corrosion, thermal-stress cracking

or mechanical rupture of the inner string, or from a packer leak. Production casing is typically designed to handle tubing leaks, but if the pressure from a leak causes a failure of the production casing, the outcome can be catastrophic. With pressurization of the outer casing strings, leaks to surface or underground blowouts may jeopardize personnel safety, production-platform facilities and the environment.

Poor mud displacement—Inadequate removal of mud or spacer fluids prior to cement placement may result in failure to achieve zonal isolation. There are several reasons for mud-removal failure, including, but not limited to, poor borehole conditions, improper displacement mechanics and failures in displacement process or execution. Inadequate removal of mud from the borehole during displacement is a major contributing factor to poor zonal isolation and gas migration. Mud displacement is discussed in greater detail (see “From Mud to Cement,” page 66).

Improper cement-slurry design—Flow occurring before cement has set is a result of loss in hydrostatic pressure to the point that the well is no longer overbalanced—hydrostatic pressure is less than formation pressure. This decrease in hydrostatic pressure results from several phenomena that occur as part of the cement-setting process.⁹ The change from a highly fluid, pumpable slurry to a set, rock-like material involves a gradual transition of the cement from fluid to gel and finally to a set condition. This may require several hours, depending on the temperature, quantity and characteristics of retarding compounds added to prevent setting of the cement prior to placement. As the cement begins to gel, bonding between the cement, casing and borehole allows the slurry to become partially self-supporting.

This self-supporting condition would not be a problem if it occurred alone. The difficulty arises because, while the cement becomes self-supporting, it loses volume as a result of at least two factors. First, where the formation is permeable, the hydrostatic pressure overbalance drives water from the cement into the formation. The rate of water loss depends on the pressure differential, formation permeability, the condition and permeability of any residual mudcake and fluid-loss characteristics of the cement. A second cause of volume loss is hydration volume reduction as the cement sets. This occurs because set cement is denser and occupies less volume than the liquid slurry. Volume loss is relatively small at first, since little solid product forms during early hydration. However,



^ Scenarios for gas flow. Shown are possible scenarios of gas migration to the surface resulting in SCP. Tubing and packer leaks may allow gas to migrate. Microannulii may develop soon or long after cementing operations. Poor mud displacement may result in inadequate zonal isolation. Gas may slowly displace residual nondisplaced drilling fluid, eventually pressurizing the annular space between tubing and casing strings. Gas may also flow through poorly designed nongas-tight permeable cement.

ultimately the volume loss can be as much as 6%.¹⁰ Volume loss coupled with the interaction between partially set cement, borehole wall and casing causes a loss of hydrostatic pressure, leading to an underbalanced condition.

While the hydrostatic pressure in the partially set cement is below formation pressure, gas may invade. If unchecked, the invasion of gas may create a channel through which gas can flow, effectively compromising cement quality and zonal isolation.

Free water in cement may also cause a channel. Under static conditions, slurry instability may lead to water separating from a cement slurry. This water may migrate to the borehole wall and collect, forming a channel. This is of particular concern in deviated wellbores where gravity may drive density separation and fluid inversion, resulting in the development of a free-fluid channel on the top side of the borehole.

Cement damage after setting—SCP can occur long after the well-construction process. Even a flawless primary cement job can be damaged by rig operations or well activities occurring after the cement has set. Changing stresses in the wellbore may cause microannuli, stress cracks, or both, often leading to SCP.¹¹

The mechanical properties of casing and cement vary significantly. Consequently, they do not behave in a uniform manner when exposed to changes in temperature and pressure. As the casing and cement expand and contract, the bond between the cement sheath and casing may fail, causing a microannulus, or flow path, to develop.

Decreasing the internal casing pressure during completion and production operations may also lead to microannuli development. Underbalanced perforating, gas-lift operations or increased drawdown in response to reservoir depletion all reduce internal casing pressure.

Any of these conditions—tubing or casing leaks, poor mud displacement, improper cement system design or damage to cement after setting—may result in flow paths for gas in the form of discrete conductive cement fractures, or microannuli. Once the gas-migration mechanism is understood, steps can be taken to mitigate the process.

Controlling Gas Migration

As the borehole reaches deeper into the earth, previously isolated layers of formation are exposed to one another, with the borehole as the conductive path. Isolating these layers, or establishing zonal isolation, is key to minimizing the migration of formation fluids between zones or



^ Cuttings response to drilling fluids. Cuttings samples were taken from a well in the southern Gulf of Mexico drilled with oil-base mud; these cuttings had not been exposed to water-base mud prior to testing. After cleaning oil from the cuttings surface, Schlumberger laboratory technicians sorted the rock pieces. Three initially identical samples of rock were photographed after receiving a different treatment. Sample A (*left*) was placed in tap water, Sample B (*middle*) into a generic lignosulfonate drilling fluid and Sample C (*right*) was immersed in a glycol-polymer-potassium chloride fluid. Each sample was rolled in a stainless-steel cell in a hot-roll oven for 16 hours at 250°F [121°C] to simulate drilling and transport up the borehole to surface. The sample in tap water, Sample A, was most damaged, and Sample C in the glycol-polymer-potassium chloride fluid was essentially undamaged. The lignosulfonate system generated intermediate damage for Sample B. Drilling with a mud having low inhibition values would be expected to generate borehole instability and washout. In contrast, excellent clay control would be obtained by a more advanced chemistry, such as glycol-polymer-potassium chloride.

to the surface where SCP would develop. Crucial to this process are borehole condition, effective mud removal, and cement-system design for placement, durability and adaptability to the well life cycle.

Wellbore condition depends on many factors, including rock type, formation pressures, local stresses, the type of mud used and drilling operational parameters, such as hydraulics, penetration rate, hole cleaning and fluid-density balance.

The ultimate condition of the borehole is often determined early in the drilling process as drilling mud interacts with newly exposed formation. If mismatched, the interaction of the drilling mud with formation clays can have serious detrimental effects on borehole gauge and rugosity. Once a well is drilled, displacement, cementing and ultimately, zonal-isolation efficiency are dependent on a stable borehole with minimal rugosity and tortuosity.

Mud companies have created high-performance water-base muds that incorporate various polymers, glycols, silicates and amines, or a combination thereof, for clay control. Today, water-base and nonaqueous invert-emulsion fluids account for 95% of all drilling fluids used. The majority, about 70%, are water-base and range from clear water to mud that is highly treated with chemicals.

Drilling fluid engineers and related technical specialists have applied various techniques to investigate rock response to drilling fluid chemistry; these include exposing core samples to

drilling fluids under simulated downhole conditions and physical examination of core and cuttings with scanning electron microscopy.¹² The results are often inconsistent, so drilling fluid selection often is based simply on field history. Many times, particularly in new fields where formation clay chemistry may be unknown, effective field development may hinge on understanding the nature of formation clays as they vary with depth [above].

6. For more on zonal isolation: Abbas R, Cunningham E, Munk T, Bjelland B, Chukwueke V, Ferri A, Garrison G, Hollies D, Labat C and Moussa O: "Solutions for Long-Term Zonal Isolation," *Oilfield Review* 14, no. 3 (Autumn 2002): 16–29.
7. Bonett A and Pafitis D: "Getting to the Root of Gas Migration," *Oilfield Review* 8, no. 1 (Spring 1996): 36–49.
8. Bourgoyne A, Scott S and Manowski W: "Review of Sustained Casing Pressure Occurring on the OCS," <http://www.mms.gov/tarprojects/008/008DE.pdf> (posted April 2000).
9. Wojtanowicz AK and Zhou D: "New Model of Pressure Reduction to Annulus During Primary Cementing," paper IADC/SPE 59137, presented at the IADC/SPE Drilling Conference, New Orleans, Louisiana, USA, February 23–25, 2000.
10. Parcevaux PA and Sault PH: "Cement Shrinkage and Elasticity: A New Approach for a Good Zonal Isolation," paper SPE 13176, presented at the 59th SPE Annual Technical Conference and Exhibition, Houston, Texas, USA, September 16–19, 1984.
11. A microannulus is a small gap between cement and a pipe or a formation. This phenomenon has been documented by running sequential cement bond logs, first with no pressure inside the casing and then with the casing pressured. The bond log clearly indicates that applied pressure often closes a microannulus.
12. Galal M: "Can We Visualize Drilling Fluid Performance Before We Start?" paper SPE 81415, presented at the SPE 13th Middle East Oil Show & Conference, Bahrain, June 9–12, 2003.

Many drilling fluid additives are available to assist the driller in formation-clay control. Lightly treated, noninhibitive mud provides good borehole cleaning and moderate filtration control for routine top-hole sections. Seawater, brackish water or field brines sometimes provide inhibition in clay-laden shale, and high salt levels, up to saturation, are used to prevent washout while drilling massive salt sections.

Where environmental regulations allow, nonwater-base muds can provide optimal borehole control. Drilling fluids based on oil- or nonaqueous-synthetic-base materials, commonly referred to as invert-emulsion muds, have evolved into high-performance systems. Even though synthetic-base mud can cost two to eight times more than conventional fluids, superior performance-to-cost ratios combined with environmental acceptability have established synthetic-base fluids as the top choice for critical wells, particularly those in which gauge hole and zonal isolation are significant concerns.

Like the fluids themselves, drilling fluid hydraulics play a fundamental role in constructing a quality borehole. Balance must be maintained between fluid density, equivalent circulating density (ECD) and borehole cleaning.¹³ If the static or dynamic fluid density is too high, loss of circulation may occur. Conversely, if

it is too low, shales and formation fluids may flow into the borehole, or in the worst case, well control may be lost. Improper control of density and borehole hydraulics can lead to significant borehole rugosity, poor displacement and, ultimately, poor cement placement and failure to achieve zonal isolation.

Rheological properties of drilling fluids must be optimized in such a way that the frictional pressure losses are minimized without compromising cuttings-carrying capacity. Optimal fluid properties for achieving good borehole cleaning and low frictional pressure loss often appear to be mutually exclusive. Detailed engineering analysis is required to obtain an acceptable compromise that allows both objectives to be satisfied [below].

In a recent deepwater project offshore Brazil, where wellbore erosion has been a severe problem, M-I's Virtual Hydraulics software established the drilling parameters and fluid properties required to provide ECD management and good borehole cleaning with reduced flow rates. In this case, less than ideal flow rates were required to minimize borehole erosion. However, carefully balancing the drilling fluid rheology, flow rate and density allowed the driller to maintain penetration rate while effectively cleaning the borehole and minimizing mechanical borehole erosion.

Software such as the M-I Virtual Hydraulics application provides an excellent tool for in-depth analysis of fluid properties and evaluation of the impact of drilling fluid parameters on downhole hydraulics and borehole erosion. During drilling, optimal fluid characteristics may change depending on the task, such as running casing or displacement of borehole fluids. Modeling and simulation can be useful in optimizing fluid properties in anticipation of changes in rig operations.

Integrating carefully designed drilling fluids with other key services is critical for achieving successful wellbore construction, zonal isolation and well longevity.

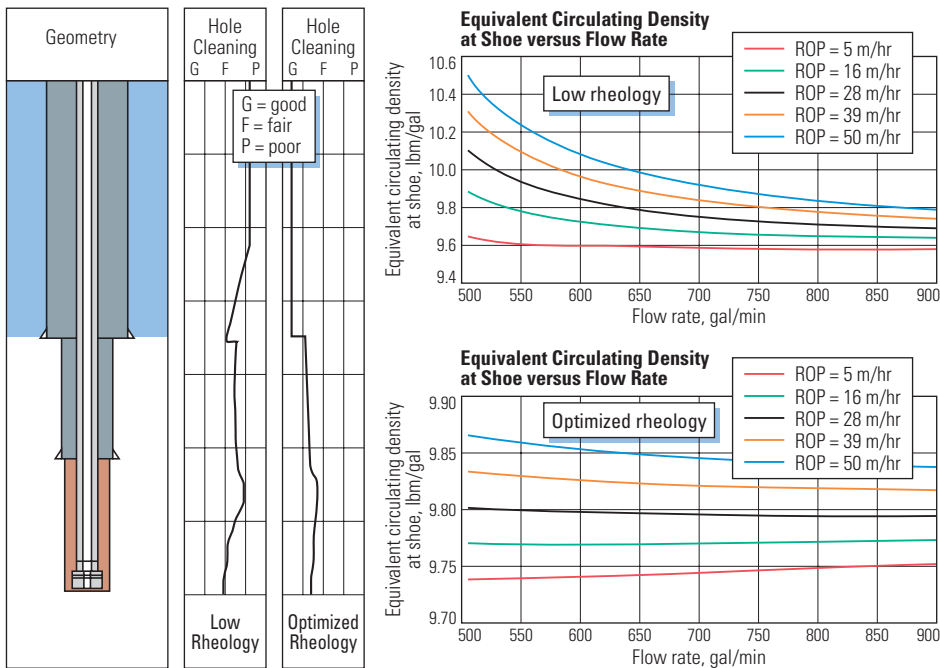
From Mud to Cement

Proper mud selection and careful management of drilling practices generally produce a quality borehole that is near-gauge, stable and with minimal areas of rugosity, or washout. To establish zonal isolation with cement, the drilling fluid must first be effectively removed from the borehole.

Mud removal depends on many interdependent factors. Tubular geometry, downhole conditions, borehole characteristics, fluid rheology, displacement design and hole geometry play major roles in successful mud removal. Optimal fluid displacement requires a clear understanding of each variable as well as inherent interdependencies among variables.

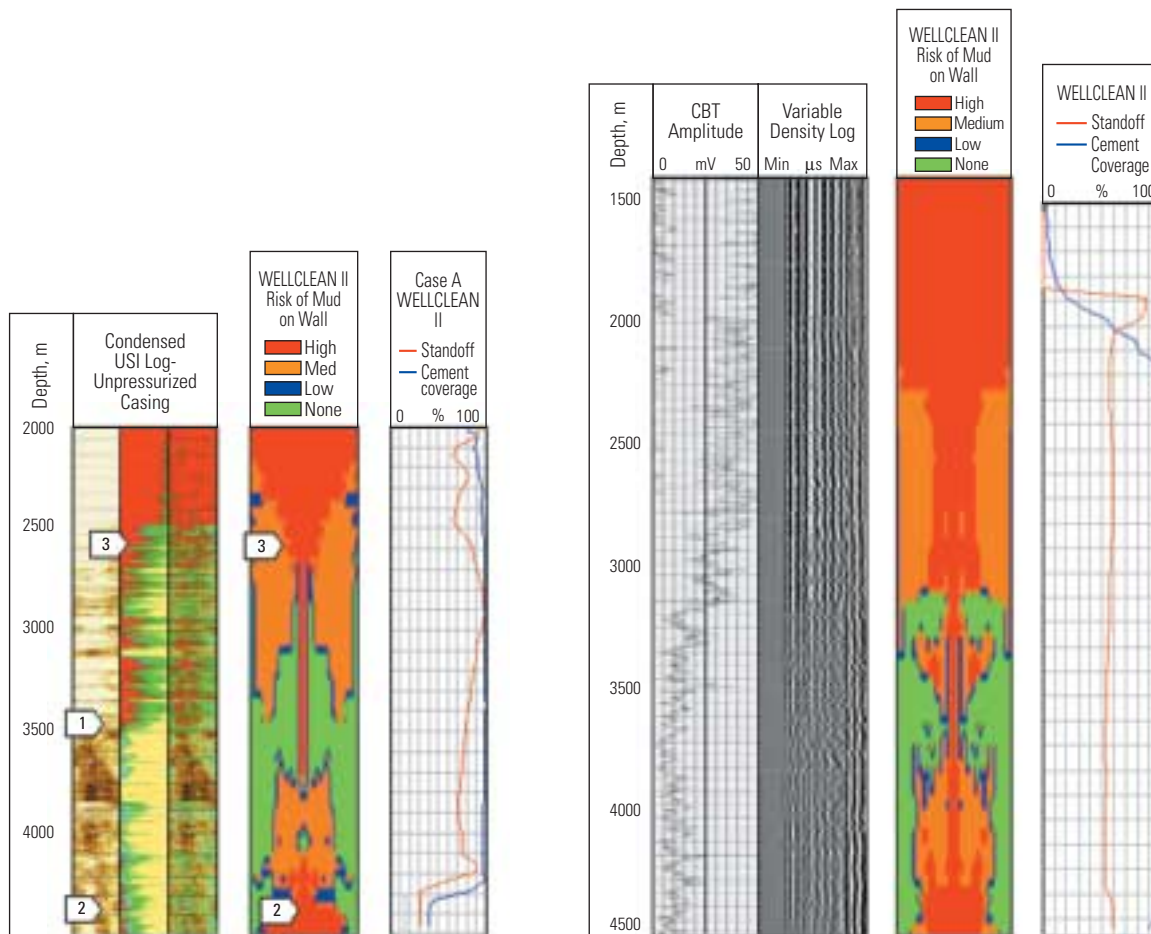
Since the early 1980s, the availability of computing technology has significantly advanced the way drillers approach wellbore displacement. Software applications and faster computer processing now allow for a significant level of prewell modeling, simulation and engineering. Fluids can be built, complex interactions predicted, and displacements simulated on the computer screen rather than at the wellsite where minor mistakes may result in major costs.

Key elements of an engineered displacement begin with an understanding of borehole characteristics such as hole size and washouts, rugosity, borehole angle and dogleg severity. Once these are understood, decisions regarding displacement flow dynamics, spacer design and chemistry, and centralization requirements can be made.



^ Optimized rheology with Virtual Hydraulics analysis. In this simulation, the M-I Virtual Hydraulics software demonstrates that borehole-cleaning capacity can be optimized against flow rate and equivalent circulating density (ECD). The simulation indicates that even when pumping at high rates, borehole cleaning (left, Track 2) with a low-rheology mud is poor in the upper sections and ECD is high (chart - upper right). Once optimized, ECD is significantly lower (chart - lower right) and borehole-cleaning efficiency improves from poor to good (left, Track 3).

13. Equivalent circulating density is the effective density exerted by a circulating fluid against the formation that takes into account the pressure drop in the annulus above the point being considered.



Flag Notes:

- 1 Poor coverage and bond after this point—lead/tail interface.
- 2 Mud on wall has produced channel, seen on USI plot also.
- 3 Increasing risk of mud on wall leads to poor cement coverage and microannuli.

^ Post-placement WELLCLEAN II analysis. Wells L10 (left) and L11 (right) were both producing at the time these simulations were run, each with SCP between the 13%- and 9%-in. casing strings. Post-placement analysis of each well indicated a high risk of mud left in the borehole, implying poor displacement and a high potential for primary cement failure and annular gas migration. The red and orange areas on Track 4 (left) and Track 3 (right) provide clear indications of the mud-removal risk level. The USI UltraSonic Imager log on the left image (Track 2) correlates with the WELLCLEAN II prejob simulation in Track 4 where poor mud removal potential is indicated. On the USI log (Track 2), the yellow shading indicates bonded cement.

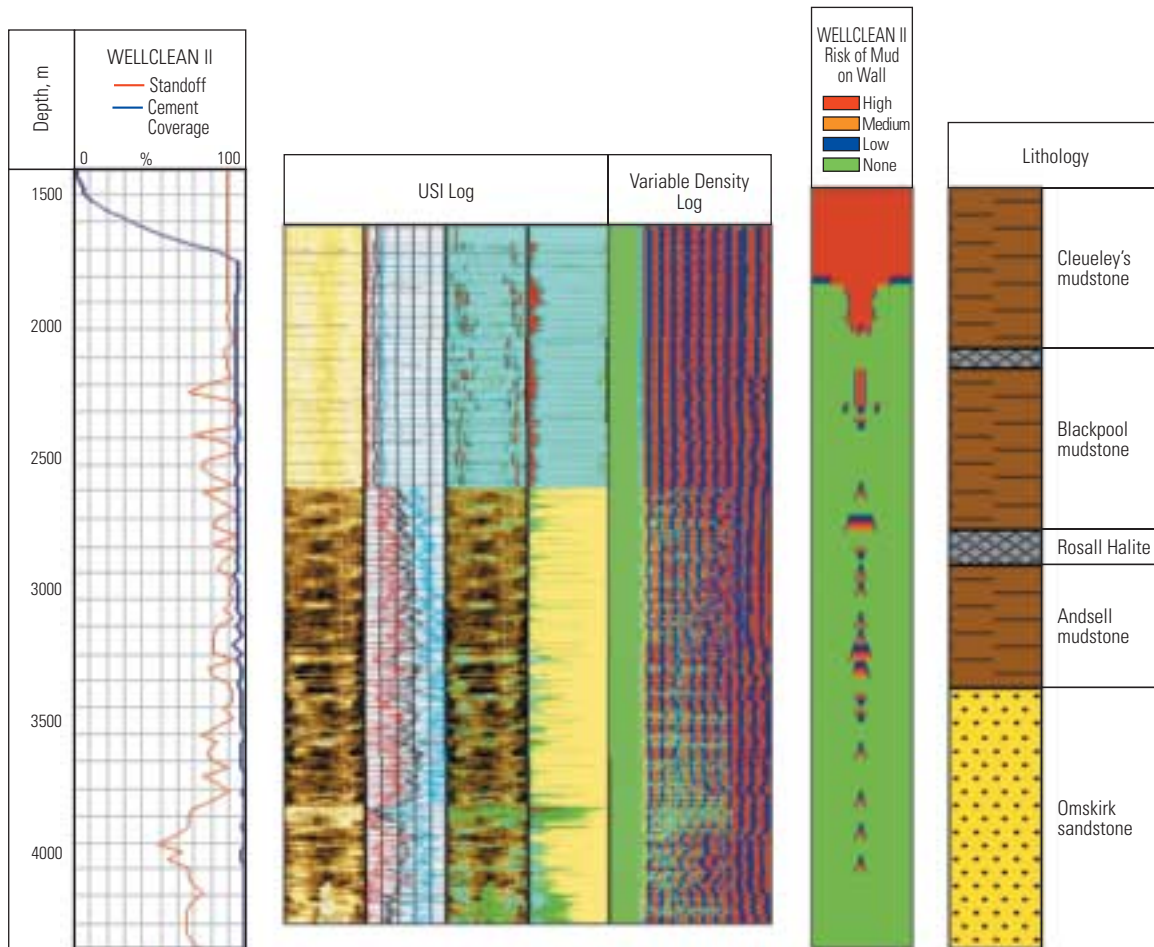
An example of an engineered displacement is seen in a case study from the Irish Sea. BHP Billiton Petroleum experienced problems resulting from poor mud removal on their Lennox field project. Located in the Liverpool Bay sector of the Irish Sea, this series of wells, producing both oil and gas, suffered repeated zonal-isolation failures and SCP occurring between the 9%-in. and 13%-in. casing strings. Aside from other pressure-related safety hazards, gas from these wells contains a high concentration of hydrogen

sulfide [H₂S], up to 20,000 parts per million (ppm), and periodic venting of annular pressure posed a serious environmental issue.

To reduce risk and establish zonal isolation on future wells, engineers from BHP Billiton and Schlumberger assessed two previous wells and developed a forward-looking plan to attack the SCP problem. Using well data from the already producing L10 and L11 wells, engineers ran WELLCLEAN II Engineering Solution simulations to determine the cause of zonal-isolation

failures. The simulation results compared favorably with the original cement bond logs and other data from both wells, confirming the accuracy and utility of the WELLCLEAN II simulations in predicting mud removal and cement placement [above].

Based on modeling of the L10 and L11 wells, the engineering team determined that poor mud removal was the primary cause of inadequate zonal isolation. Utilizing CemCADE cementing design and simulation software and



^ Results of a prejob displacement simulation. Prior to cementing the 9%-in. casing string on the L12 well, engineers modeled and simulated borehole conditions and displacement parameters using WELLCLEAN II software. By optimizing mud properties and spacer and cement design, along with proper centralization, the simulation predicted near-complete displacement of the drilling fluid (Track 7). A USI log run after cementing confirmed proper placement and zonal isolation as seen in Tracks 2 through 5. The yellow shading in Track 5 indicates optimal cement bonding. Well L12 is currently producing with no detectable SCP.

WELLCLEAN II software, engineers designed and executed a displacement and cementing program on Well L12, effectively eliminating SCP development [above]. Optimizing spacer design, the casing centralization program and cement properties led to effective displacement and cement bonding, bringing significant value to the operator.

Gas Isolation with Cement

Integration of drilling fluids, spacer design and displacement techniques provide the foundation for optimal cement placement.¹⁴ Long-term zonal isolation and control of gas require the cement to be properly placed and to provide low permeability, mechanical durability and adaptability to changing wellbore conditions.

Cement permeability depends on the solid fraction of the formulation. For high-density

slurries, a high solid fraction is inherent, thus the permeability tends to be low. For low-density slurries, special products and techniques create low-density, high solid-fraction slurries.

Mechanical durability varies with strength, Young's modulus of elasticity and Poisson's ratio. The cement should be designed so these properties are sufficient to prevent failure of the cement when it is exposed to changing well pressures and temperature fluctuations, which create stresses across the casing-cement-formation system. Special materials are required to give the cement flexibility in this environment.

During placement, overbalance must be maintained across gas-bearing formations until the vulnerability of the cement to invasion by gas is reduced through the setting process. The higher the overbalance, the later in the hydration cycle invasion can occur.

A technique for increasing or maintaining overbalance is the application of pressure to the annulus following the cementing operation—usually by applying pump pressure to the annulus at the surface. In Canada, a common practice is to pump rapidly setting cement ahead of more conventional cement. This allows the first cement pumped, or lead cement, to set in the annulus near the surface. Pressure can be applied through the casing to the cement that has been slightly underdisplaced. A precaution to the application of pressure is that weak formations must be evaluated for the risk of losses.

A modification of this pressure application is a technique called cement pulsation, the application of pressure pulses to the annulus following the cementing operation.¹⁵ The advantage of this technique is that the pressurization-depressurization cycles generate a small amount

of motion of the fluids in the wellbore, delaying gel-strength development, and thereby slowing hydrostatic-pressure decay.

Foamed cement may also be used across gas formations. As volume decreases through dehydration, the pressure-volume relationship of the compressed gas used in the foaming process allows a higher pressure to be maintained against the formation, thus minimizing gas influx.

Planning for Gas

Sealing an annular space against gas migration can be more difficult in gas wells than in oil wells. Wellbore construction, particularly in the presence of gas-bearing formations, requires that borehole, drilling fluid, spacer and cement designs, and displacement techniques be dealt with as a series of interdependent systems, each playing an equally important role. Often, the relationships among these systems is overlooked, or at the very least, poorly appreciated.

Effective management of these interdependent technologies requires that drillers and cementers work together throughout the drilling process, selecting muds that achieve drilling goals while managing the borehole in a manner that allows effective mud removal and zonal isolation. Efficient slurry placement for complete and permanent zonal isolation relies on effective displacement of drilling fluids from the borehole—modeling, simulation and spacer system design play key roles in this process, as illustrated in an example from South America.

In early 2002, Petrobras, operating in a remote region of southern Bolivia, experienced repeated occurrences of SCP on their Sabalo project in the San Antonio field [right]. Each of the first three 13 $\frac{3}{8}$ -in. surface casing primary cement jobs developed SCP, some as high as 1000 psi [6895 kPa]. Pressure was also detected on several 9 $\frac{5}{8}$ -in. intermediate and 7-in. production-liner casing strings.

The next borehole segment to be drilled was the 8 $\frac{1}{2}$ -in. deviated section of the X-3 well, which would traverse the gas-laden, potentially commercial, Huamampampa formation. Concerns over lubricity in a deviated borehole, minimizing production zone damage and the requirement for an in-gauge stable borehole led the drilling team to select a low-fluid-loss VERSADRIL oil-base mud system.

Fluid-loss control, bridging and filter-cake quality are important drilling-fluid properties for minimizing both formation damage and excessive filter-cake buildup across permeable zones.

Formation damage issues aside, excessive filter-cake buildup can severely hamper mud displacement prior to cementing. The filtration properties of the system were controlled utilizing a blend of high melting-point gilsonite and specifically sized calcium carbonate particles.

The inclination of the borehole caused operational concerns about borehole cleaning and barite sag.¹⁶ Cuttings-bed development and static sag problems are most prevalent at 30 to 60 degree borehole inclination; either condition could result in borehole destabilization. Since

the X-3 borehole inclination was 62 degrees, the well was considered high risk.

To mitigate these concerns, the driller maintained high annular flow rates, and the drilling fluid engineer adjusted the mud-product mix to produce higher viscosity at low shear rates. Strict adherence to these and other good drilling practices minimized the accumulation of cuttings along the lower side of the borehole and minimized borehole erosion. No evidence of sag was recorded. The 8 $\frac{1}{2}$ -in. interval was drilled with a mud weight of 14.1 lbm/gal [1690 kg/m³]

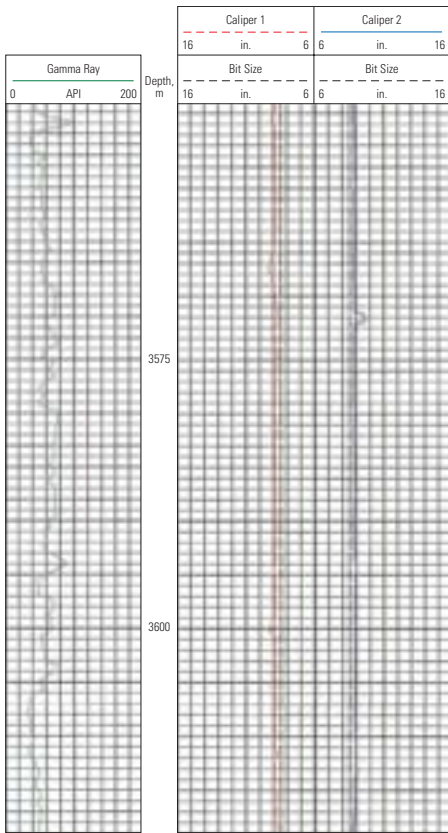


▲ Petrobras remote location drilling. Petrobras is drilling multiple well templates in the San Antonio field in southern Bolivia.

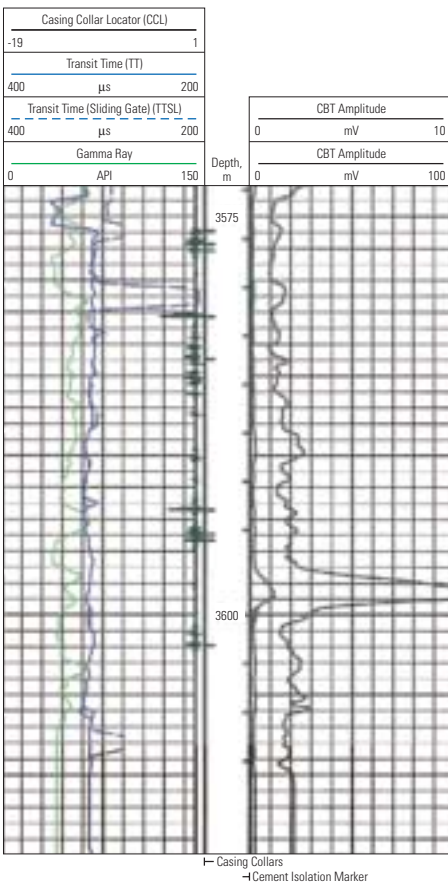
14. Fraser L, Stanger B, Griffin T, Jabri M, Sones G, Steelman M and Valkó P: "Seamless Fluids Programs: A Key to Better Well Construction," *Oilfield Review* 8, no. 2 (Summer 1996): 42–56.

15. Dusterhoft D, Wilson G and Newman K: "Field Study on the Use of Cement Pulsation to Control Gas Migration," paper SPE 75689, presented at the SPE Gas Technology Symposium, Calgary, Alberta, Canada, April 30–May 2, 2002.

16. Sag is defined as settling of particles in the annulus of a well, which can occur when the mud is static or being circulated. Because of the combination of secondary flow and gravitational forces, weighting materials can settle, or sag, in a flowing mud in a high-angle well. If settling is prolonged, the upper part of a wellbore will lose mud density, which lessens the hydrostatic pressure in the hole, allowing an influx of formation fluid to enter the well.



▲ Well X-3 caliper logs. Tracks 2 and 3 indicate a near-gauge borehole.



from 10,981 to 11,870 feet [3347 to 3618 m]. At total depth (TD), the four-arm wireline caliper log indicated excellent borehole conditions [left].

Proper fluid design, on-site engineering and proper drilling practices provided a clean in-gauge borehole. Engineers optimized the spacer system for actual borehole conditions, mud characteristics and liner design. Based on WELLCLEAN II and CemCADE simulator recommendations, 40 centralizers, one per casing joint, were placed on the liner. Since an oil-base mud was used for drilling, a MUDPUSH XLO spacer system for cementing with surfactant at 12 gal/1000 gal [286 cm³/m³] and mutual solvent at 100 gal/1000 gal [2380 cm³/m³] was designed for optimal mud removal.

Because the Huamampampa formation typically contains a high level of gas, Schlumberger cementing specialists designed a 16.6-lbm/gal [1989-kg/m³] DensCRETE slurry system incorporating a gas-control additive to prevent gas migration after cement placement. To minimize cement slurry dehydration across permeable zones, API fluid loss was controlled at 19 mL/30 min.¹⁷

Displacement and cementing operations were executed according to stringent design specifications. On reentering the borehole, the driller located the top of cement at 10,646 ft [3245 m] measured depth (MD), 335 ft [102 m] below the top of the tieback, or overlap between the liner and previous casing string.

Petrobras routinely evaluates primary cement using cement bond logs and formation leakoff tests. A CBT Cement Bond Tool Variable

Density log was run three days after the cementing operation.¹⁸ The CemCADE simulator predicted a CBT amplitude of 1.7 mV for 100% mud removal and 3.1 mV for 80% mud removal. The logging results indicate an average amplitude of around 2 mV, so the 7-in. liner cement job had a 95% average bond index [below left]. These results agree with CemCADE and WELLCLEAN II predictions. Good zonal isolation was achieved.

The holistic approach to gas-migration control adopted by the engineering teams, combined with state-of-the-art technology, resulted in effective zonal isolation with no gas leakage to surface. As of September 2003, after producing as much as 20 MMscf/D [0.57 m³/d] of gas for over a year, the X-3 well has shown no indication of microannuli or SCP development. By applying an integrated approach to wellbore planning and construction, the engineering team successfully modified their operational, drilling fluids and cementing programs to achieve zonal isolation on two subsequent casing strings.

A Solution for Shallow-Gas Isolation

Shallow-gas flows present a specialized problem in the control of gas migration. While operating in the Gulf of Thailand in the fall of 2001, PTT Exploration and Production Public Company Ltd. (PTTEP) experienced serious problems with shallow-gas flows and SCP development. Originally discovered in 1973, the Bongkot field is 600 km [373 miles] south of Bangkok, Thailand, and 180 km [112 miles] off the coast of Songkhla. The field primarily consists of gas reserves with some limited oil production.

The WP11 drilling project was part of a 12-well development-drilling program. Geophysical and wireline log data indicated the potential for shallow gas at a depth of 312 to 326 m [1023 to 1069 ft] below mean sea level. PTTEP engineers planned to set 13½-in. casing at 310 m

< Well X-3 casing bond log. The CBT Cement Bond Tool Variable Density log was run three days after cementing. The average CBT amplitude was 2 mV (Track 2) across the gas zone, which was extremely low for wells in the area. Amplitude values decrease with cement bond quality. The 8½-in. borehole was drilled at a 62° angle with oil-base mud at 14.1 lbm/gal [1689 kg/m³]. Borehole conditions were excellent for displacement and cementing. No SCP has been detected, indicating successful zonal isolation.

17. This is the American Petroleum Institute (API) standard for cement fluid loss.

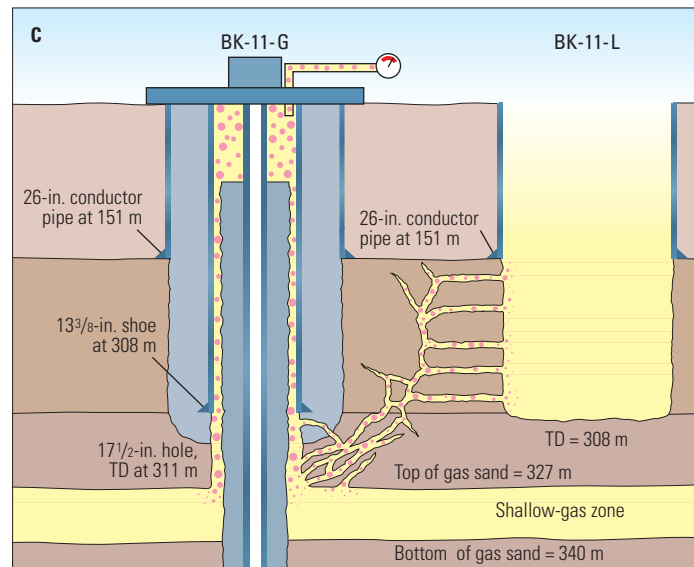
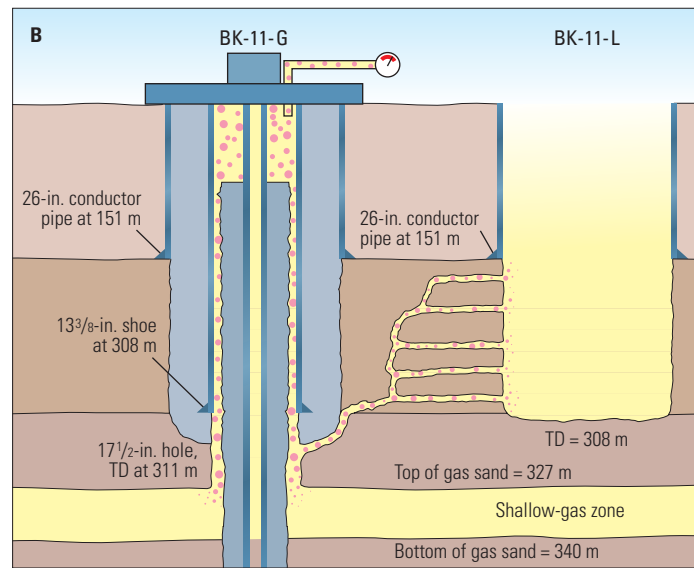
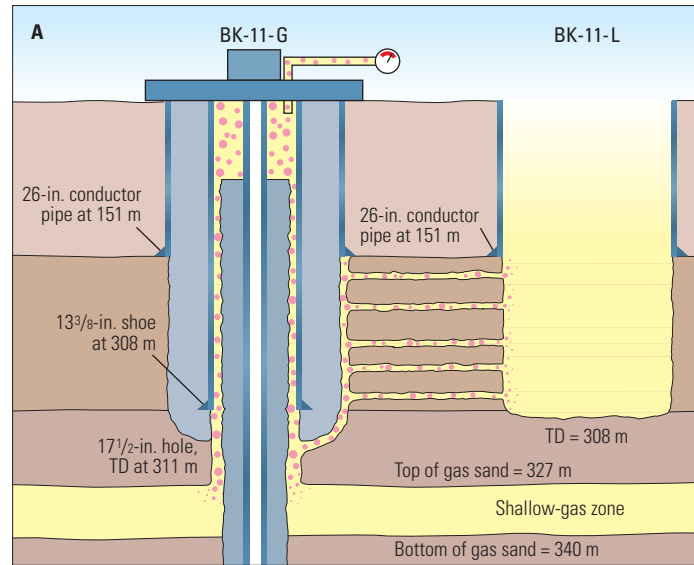
18. Butsch RJ, Kasecky MJ, Morris CW and Wydrinski R: "The Evaluation of Specialized Cements," paper SPE 76731, presented at the SPE Western Regional/AAPG Pacific Section Joint Meeting, Anchorage, Alaska, USA, May 20–22, 2002.

[1017 ft], then drill a 12½-in. borehole through the shallow-gas sand and set 9½-in. casing at about 500 m [1640 ft]. Zonal isolation behind the 9½-in. casing was critical to the success of the project. Even though a gas-tight, or gas-influx-resistant, cement-slurry design was used, the first three 9½-in. casing primary cement jobs failed, resulting in both SCP at the surface and gas charging of upper-zone normally pressured sands [right].

Although not under contract for the project, Schlumberger and M-I engineers working in conjunction with PTTEP and their partners, Total and BG, proposed a plan to integrate borehole stabilization with mud displacement and cement-system design.

The shallow formations in the 12½-in. section consisted primarily of sand and shale, 30 to 40% of which was reactive clay. Historically, conventional water-base muds had been used to drill these formations, resulting in significantly washed-out sections, poor displacements, inadequate primary cement placement and loss of zonal isolation.

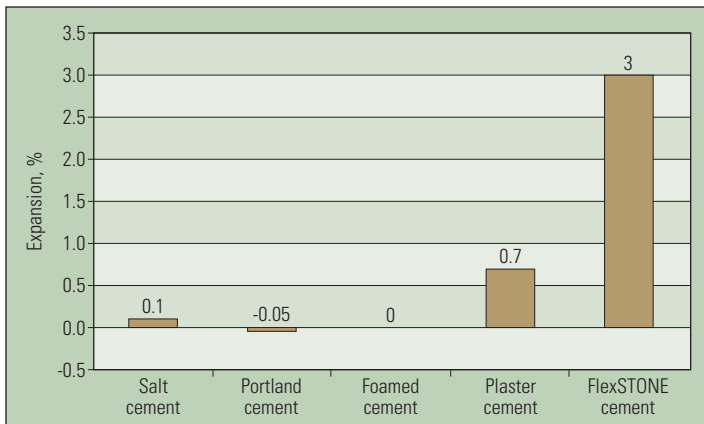
The M-I engineering team recommended controlling the borehole and cuttings integrity with SILDRIL mud, a sodium-silicate-base drilling fluid. The objective was to obtain a near-gauge borehole allowing optimized casing centralization, mud displacement and cement placement across the gas-bearing sand.



> Scenarios for upper-sand charging. In early drilling operations, previously nongas-bearing upper sands were charged with gas. Several scenarios were developed to explain gas cross-flow between Wells BK-11-G and BK-11-L, and the development of SCP at surface. Gas is shown as red bubbles originating in the shallow-gas sand. In the three scenarios shown, gas migrates around poorly bonded cement (A). Gas moves around poorly bonded cement to vertical fractures (B). It migrates around poorly bonded cement and through a microfracture network (C). In all cases, primary cement failed to provide zonal isolation, resulting in gas migration to both upper sands and between casing strings, resulting in SCP.



^ Controlling cuttings with silicate mud. The SILDRIL silicate-base mud, used to drill the 12¼-in. sections, produced a stable borehole with an average diameter of 12.54 in. [318 mm]. Cuttings shown crossing the shaker have a high level of integrity, confirming control of formation clay hydration and dispersion.



^ Changing volume of cement during the setting phase. Most cements have only a slight volume change during the setting process. FlexSTONE advanced flexible cement system can be formulated to expand by as much as 3%.

Silicate muds have proved useful in stabilizing the erosion of shallow unconsolidated formations and in providing gauge boreholes while maintaining optimal penetration rates. In highly reactive formations such as those encountered on the WP11 project, silicate ions bond with active sites on formation clays. This results in highly competent cuttings and borehole stabilization through direct chemical bonding of the polymerized silicate [top].

Spacer design and mud displacement were the next challenge. Schlumberger engineers, using WELLCLEAN II simulations, designed a spacer system composed of MUDPUSH XL spacer and CW7 chemical wash to efficiently remove the SILDRIL fluid from the borehole prior to placing cement. The design used 22 casing centralizers to provide better than 75% standoff. A pump rate of 7 bbl/min [1 m³/min] would allow 5 minutes of spacer contact time across the gas sand at 327 m [1073 ft]. WELLCLEAN II modeling predicted 100%

cement coverage across the openhole section. For added safety, PTTEP engineers planned for an external casing packer (ECP) to be placed just above the gas sand.

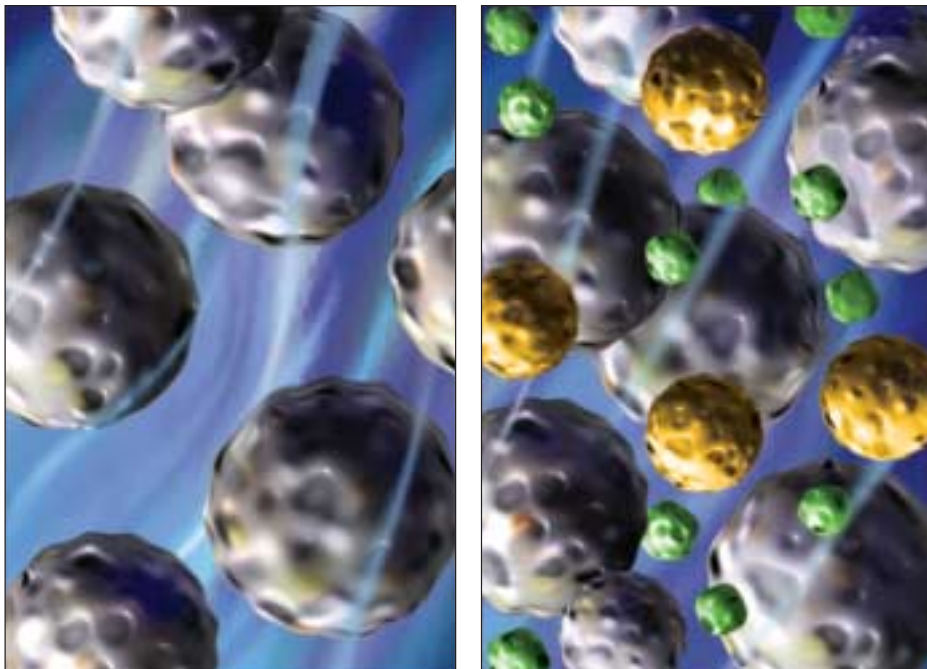
Cement-slurry design was also challenging. To avoid losses while cementing, a lightweight gas-tight cement slurry was required. The low borehole temperature, 35°C [95°F], meant long cement setting time. Low fluid loss and rapid static gel-strength development during cement setting would aid in minimizing gas influx. Schlumberger engineers designed a low-temperature LiteCRETE cementing system containing GASBLOK LT gas migration control cement system additive and DeepCEM deep-water cementing solutions additive to minimize the transition time from liquid to solid, thus limiting gas-migration potential through the setting cement.

Caliper logs indicated an average borehole diameter of 12.54 in. [318 mm]—optimum formation-clay inhibition had been achieved using the SILDRIL mud system. Although four of seven ECPs failed to lock after inflation, the LiteCRETE cementing system in conjunction with a gauge borehole, an optimized spacer system and effective displacement provided excellent cementation and zonal isolation. Ultimately, there was no evidence of gas migration or SCP behind the 9½-in. casing string.

An integrated drilling and wellbore-fluids approach effectively isolated the troublesome gas zone at 327 m [next page, bottom]. Although consideration had been given to changing locations to avoid the shallow-gas sand, this solution allowed PTTEP to keep the platform in place and continue the drilling program. Seven wells have since been successfully completed.

Improving Cement Bond over Time

Preventing gas migration and SCP has been helped by recent developments in cementing technology that offer significant advantages in durability and adaptation to changing wellbore conditions. Cement properties have traditionally been designed for optimal placement and strength development rather than long-term post-setting performance. The rapid development of high cement-compressive strength after placement was generally considered adequate for most wellbore conditions. Today, operators and service companies realize that the emphasis on strength at the expense of durability has often led to the development of SCP and reduced well productivity.



^ Filling the voids. The void space between particles in standard cements (*left*) is filled with water. FlexSTONE systems fill the void space with medium and small particles (*right*). Less water is used in the formulation, and slurries can be made more gas-tight, stronger and more flexible. As the cement sets, specific particles in the FlexSTONE system contribute to expansion while others are designed to provide flexibility of set cement.

Cement particle characteristics and size distribution can contribute significantly to both the resistance to gas influx and maintenance of a sustainable hydraulic seal, particularly in wellbores subjected to pressure and temperature cycling. FlexSTONE advanced flexible cement technology, part of the CemCRETE concrete-based oilwell cementing technology, is one of several solutions that effectively address cement flexibility and durability.

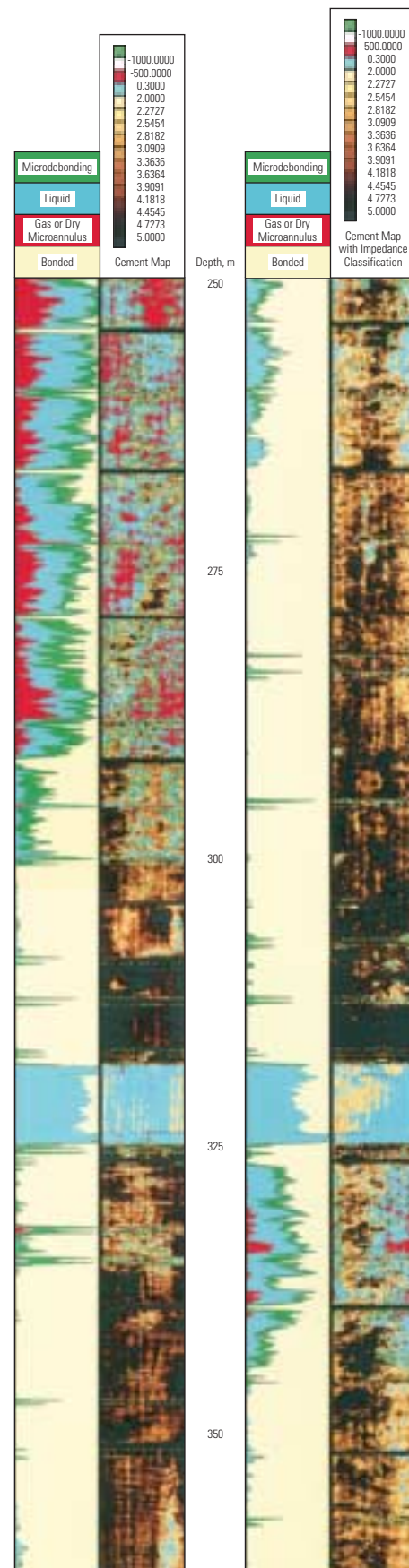
Conventional Portland cements are known to shrink during setting [previous page, middle].¹⁹ In contrast, FlexSTONE slurries can be designed to expand, further tightening the hydraulic seal and helping to compensate for variations in borehole or casing conditions. This capability helps avoid microannuli development. By adjusting specific additive characteristics and by blending the cement slurry with an engineered particle size distribution, a lowering of Young's modulus of elasticity in cement can be achieved [above]. Annular cement can then flex in unison with the casing rather than failing from tensile stresses.

19. Dusseault MB, Gray MN and Nawrocki PA: "Why Oilwells Leak: Cement Behavior and Long-Term Consequences," paper SPE 64733, presented at the SPE International Oil and Gas Conference and Exhibition, Beijing, China, November 7–10, 2000.

Thus, the potential development of microannuli and gas communication to the surface or to zones of lower pressure are minimized.

An example of the expansion capabilities of FlexSTONE cement comes from the Middle East. During 2002, Abu Dhabi Marine Operating Company (ADMA), operating the Umm Shaif field, 20 miles [32 km] northeast of Das Island, offshore Abu Dhabi, UAE, used an expandable FlexSTONE cement system to address recurrent gas-migration problems behind 9½-in. casing strings.

> Improved zonal isolation. Prior to optimization of the drilling and cementing process, zonal isolation was not obtained, as indicated by Tracks 1 and 2 (*left*). Areas shaded in red in Track 2 indicate gas. In Track 1, blue and green shadings along the left side indicate the presence of liquid and debonding respectively, signs of a potential gas channel. Effective procedures and optimized wellbore-construction processes successfully isolated the gas sands. In the figure at right, Track 1 shows areas of solid yellow, indicating bonded cement and zonal isolation. Significant levels of gas are seen only proximal to the shallow-gas sand.



While logging the 7-in. liner section, the operator ran a USI UltraSonic Imager log for a second time across the 9 $\frac{7}{8}$ -in. section cemented with a FlexSTONE cement two months earlier. Although a gas-tight seal was obtained during primary cementation, further tightening of the cement bond occurred with time. This finding demonstrates the expansive characteristics of the FlexSTONE design [right].

Modeling Cement Systems

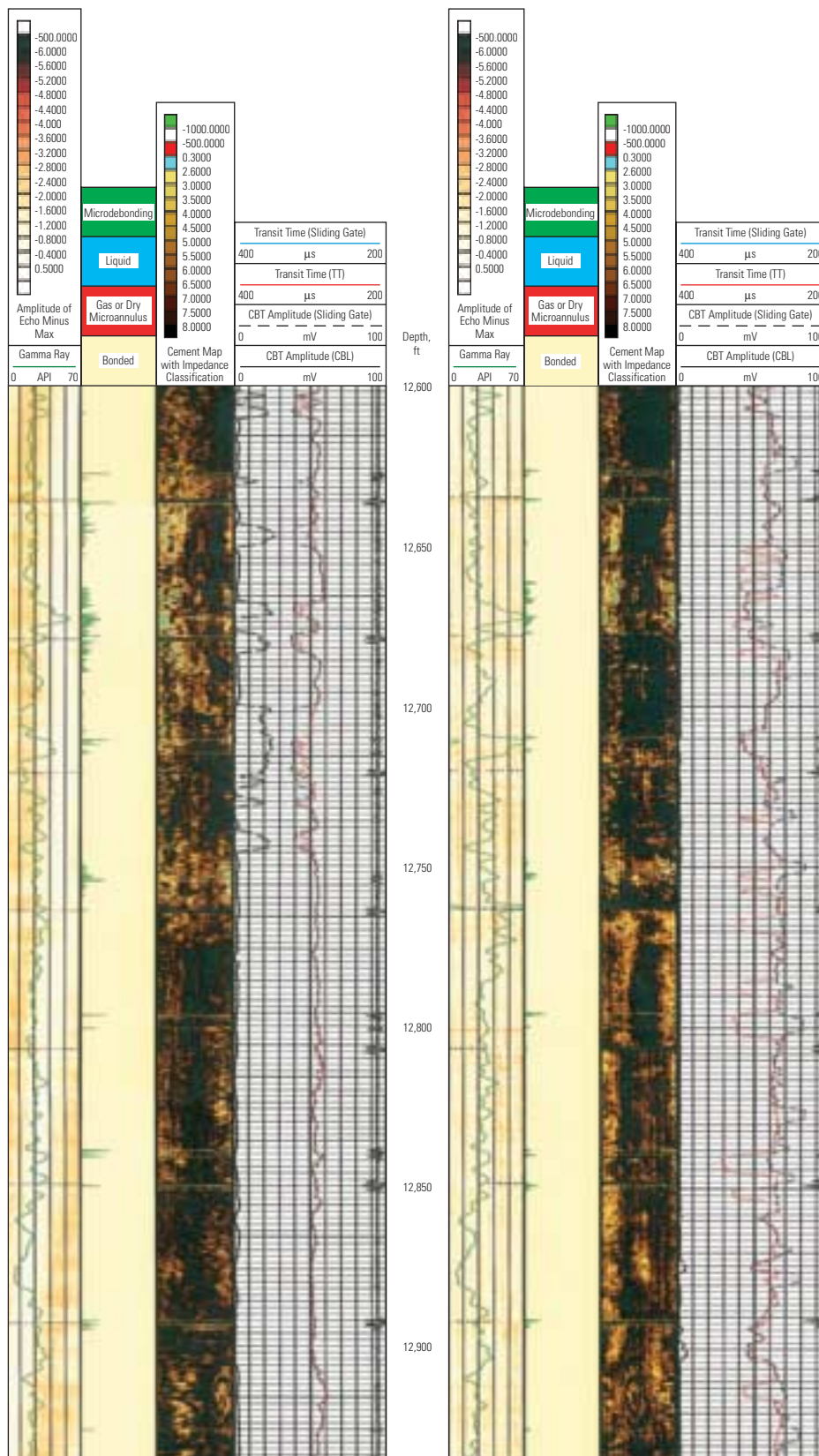
The role of modeling in cement-system design is evident in another Middle Eastern example. The Abu Dhabi Company for Onshore Oil Operations (ADCO) has drilled 70 gas wells in the Bab and Asab fields, offshore Abu Dhabi. Many of these wells have SCP problems, attributed by ADCO engineers to poor primary cementing practices.

These SCP problems threatened a 2003 development program. A different approach to cement-sheath integrity was needed. A planned horizontal, gas-producing appraisal well offered the opportunity to test a new cementing system.

Schlumberger and ADCO engineers agreed that historical failure mechanisms must be clearly understood to achieve sustainable zonal isolation. Schlumberger engineers used a stress analysis model (SAM) to evaluate potential cement systems. They ran a series of simulations to predict cement-sheath behavior across different borehole sections. In one scenario, an 80-lbm/ft³ [1280-kg/m³] mud system was displaced from the cased wellbore with a 74-lbm/ft³ [1184-kg/m³] completion fluid. The displacement resulted in a pressure reduction of 540 psi [3723 kPa] across the liner section.

Typically, these liner sections are cemented with 125-lbm/ft³ [2000-kg/m³] conventional cement systems. Laboratory records indicated that locally formulated conventional cement systems generally have an unconfined compressive strength (UCS) of about 4000 to 8000 psi [27 to 55 MPa] and a Young's modulus of 1,450,000 psi [10,000 MPa] to 1,700,000 psi [11,721 MPa]. Simulations with the SAM model predicted that a 540-psi decrease in hydrostatic pressure inside the casing would result in cement-to-liner bond failure and development of a channel or microannulus. The model suggested that a more flexible expanding cement would withstand the variation in internal casing pressure without causing microannulus development.

While SAM modeling and other analyses were under way, appraisal-well drilling began. The 9 $\frac{7}{8}$ -in. section was cemented with a conventional cement system, allowed to set and then



▲ FlexSTONE cement expansion with time. USI logs of a borehole made in October (left) and December (right) indicated cement expansion over the two-month period. Track 2 indicates more debonding (green) in October than in December (Track 6). The reduction in CBT amplitude in Tracks 4 and 8 also indicates improved bonding.

logged with a USI tool to evaluate the cement bond. Once the cement had cured, the operator pressure-tested the section to 3500 psi [24 MPa]. To check cement integrity, USI logs were rerun under the same conditions as the first logging run. The second log indicated that the nonflexible conventional cement-system formulation failed to produce a slurry capable of compensating for casing deformation, resulting in loss of cement-to-casing bond [right].

Even though the casing had already been cemented, Schlumberger engineers simulated the pressure-test conditions in SAM. Cement properties were imported from the job design for analysis. SAM predicted that the conventional cement slurry would fail in tensile load. The model indicated that the change in internal casing pressure exceeded the cement tensile strength by 153%. To withstand this level of tensile load, the SAM model recommended cement designed with a Young's modulus of 1,200,000 psi [8273 MPa], 500,000 psi [3447 MPa] below that typical for conventional cement-system formulations.

Additional SAM modeling and cement slurry tested in the Schlumberger laboratory indicated that the FlexSTONE cement system would provide sustainable zonal isolation under anticipated downhole conditions [below]. The results suggested that both the expansive and flexible properties of FlexSTONE cement would be required to effectively cement the 7-in. liner section.

As with many high-performance cementing systems, FlexSTONE cements must be carefully designed. The increase in flexibility is associated with a decrease in compressive strength. Thus,

compressive strength cannot be used as a primary indication of a cement's long-term durability. The cement systems must be designed to ensure a compromise between both properties. After evaluating several potential slurries including tests to determine the balance between expansion and the compressive-strength requirements, engineers settled on a suitable FlexSTONE cement formulation for the 7-in. liner.

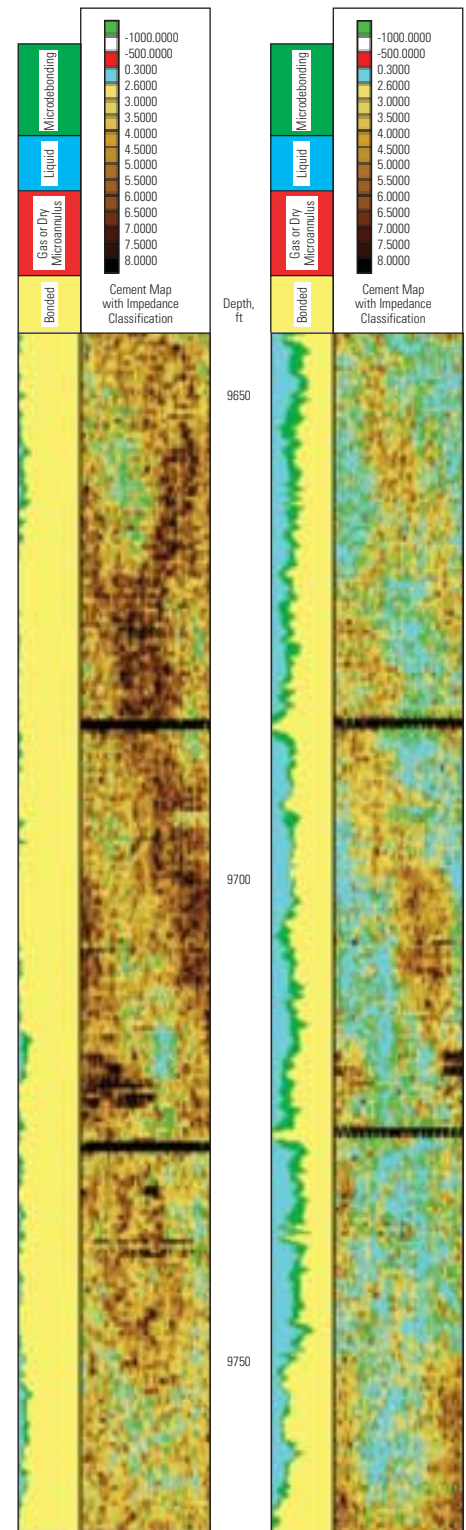
The 8½-in. borehole section would be drilled through a limestone formation. Special mud systems generally are not necessary when drilling through carbonate rock. Engineers could safely assume that borehole conditions would be optimal with little washout. The WELLCLEAN II program simulated and designed the displacement, and CemCADE software provided cement-job design and execution guidelines.

Engineers designed the BB-545 appraisal well with a 7-in. liner section extending to 11,621 ft [3542 m] MD, (11,104 ft [3385 m] TVD). This section ended with a 90° section in the Arab ABC reservoir, a gas-bearing formation with 32% H₂S content. The liner overlap, potentially a problematic source of SCP, extended 365 ft [111 m] back into the 9½-in. casing. Well production came from a 2250-ft [686-m], 6-in. openhole horizontal section drilled from the 7-in. liner shoe.

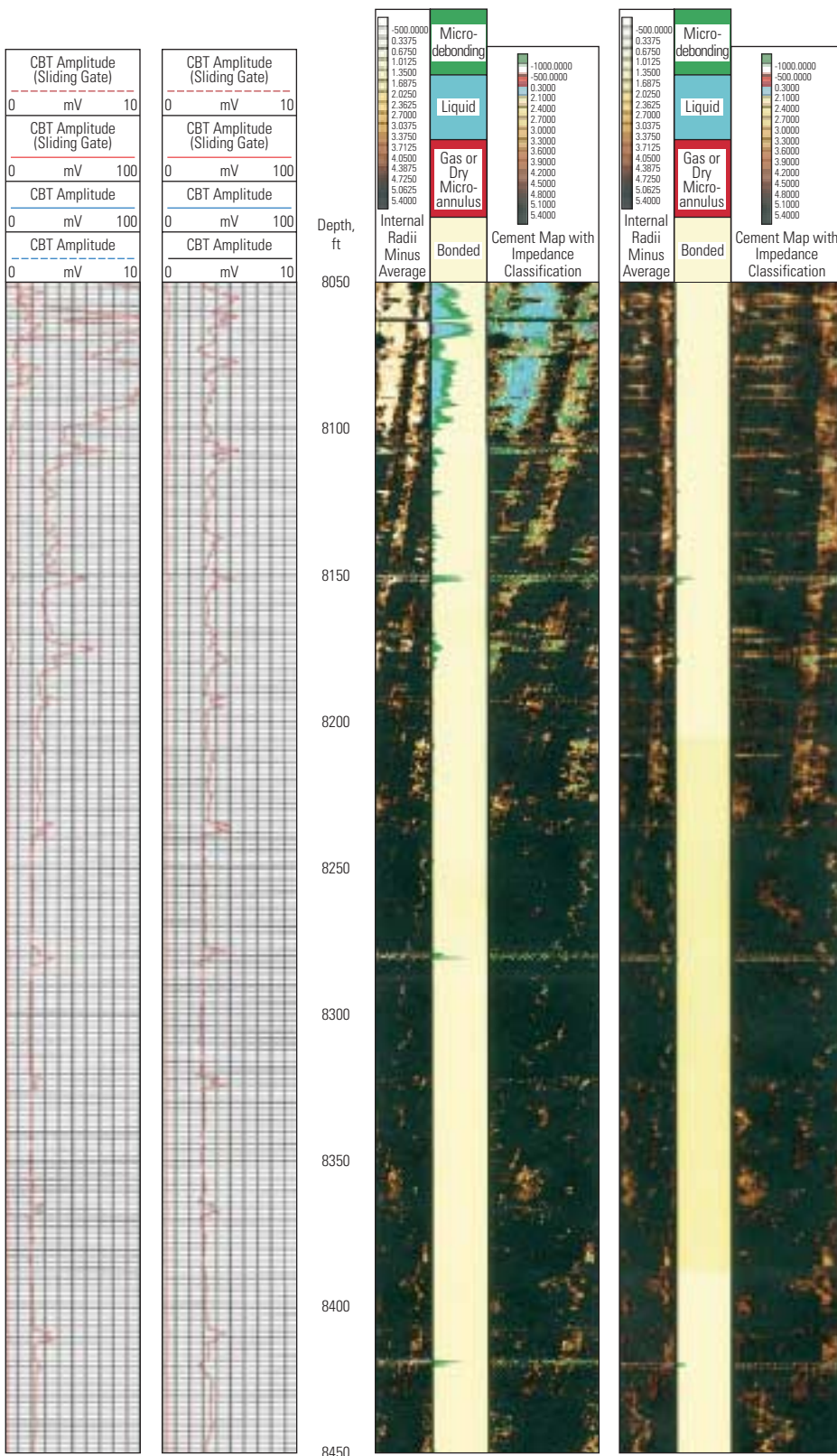
On February 4, 2003, the 7-in. liner was cemented as designed. After the cement had set, a USI log confirmed complete cement placement with no detectable channels or microannuli. After seven months, the BB-545 appraisal well showed no sign of SCP.

Slurry	Young's Modulus, psi	Poisson's Ratio
Slurry 1—FlexSTONE	900,000	0.20
Slurry 2—Type G conventional cement 1	1,700,000	0.19
Slurry 3—Type G conventional cement 2	1,500,000	0.22

^ Flexible cement designs. The FlexSTONE system was designed with a 50% lower Young's modulus than conventional slurry to meet the specifications determined from SAM simulations. Slurry 2 reflects the properties for the conventional cement slurry used to cement the 9½-in. casing string. FlexSTONE Slurry 1, which has a substantial increase in flexibility, was used to cement the 7-inch liner section.



^ Cement debonding after pressure-testing. The USI log image (left) shows well-bonded cement in Track 1 (yellow). After the well was pressure-tested to 3500 psi [24 MPa], another USI log was run (right). When the pressure was removed, the casing decreased in size but the cement sheath did not move, or flex, with the casing. Near total debonding resulted as indicated in Track 3 (blue).



▲ Zonal isolation on Well BB-548. Both CBT (*left, Tracks 1 and 2*) and USI (*right Tracks 3 to 6*) logs were obtained while logging the 9½-in. casing section of Well BB-548 in April and again in June. The April USI results in Track 4 indicated good overall bonding (yellow) with a few small liquid zones (blue). These zones, shown in the April CBT log (Track 1/8080 ft [2463 m]), reflect a CBT amplitude of 20 mV. As indicated by less liquid in the June USI result (Track 7) and a drop of CBT voltage to 5 mV (Track 2), pressure-testing did not affect the hydraulic seal developed by the expansive and flexible FlexSTONE cement. In Tracks 1 and 2, the CBT amplitude and CBT amplitude (sliding gate) essentially overlap one another.

FlexSTONE cement was also used to cement the 9½-in. casing section of Well BB-548, a well-bore similar to the BB-545 well that also penetrated the Arab ABC formation. Even though the well underwent significant pressure variations during testing, USI logs run after 72 hours and again after two months indicated sustained zonal isolation and improved bonding with time [left].

The Future under Construction

Gas migration and sustained casing pressure occur with unpredictable frequency in many parts of the world. Regulatory agencies and the oil and gas industry both have a vested interest in focusing on factors contributing to its development and prevention.

Continuing efforts to develop sound well-construction practices will eventually mitigate the frequency of SCP development. Further advances are needed, particularly in the areas of monitoring wells, locating the source of leaks and providing cost-effective methods of repair.

Operator experiences presented in this article demonstrate that integration of interdependent services and technologies coupled with advances in simulation, modeling and product technologies have moved the industry forward in addressing gas-well security and potentially, gas-well longevity—DW