

Drilling and Testing Hot, High-Pressure Wells

As cars get more powerful, driving is made safer by widening roads and enforcing speed limits.

Similar tactics are used to safely drill and test high-temperature, high-pressure wells. To meet extreme well conditions, higher capacity hardware is deployed—the road is widened. Then, to maintain a speed limit, tight controls are implemented to ensure that safety margins remain unbreached.



Robert MacAndrew
Ranger Oil (UK) Ltd
Aberdeen, Scotland

Nigel Parry
Phillips Petroleum Company
United Kingdom Ltd
Aberdeen, Scotland

Jean-Marie Prieur
Conoco (UK) Ltd
Aberdeen, Scotland

Jan Wiggelman
Shell UK Exploration and Production
Aberdeen, Scotland

Eric Diggins
Brunei Shell Petroleum
Brunei

Patrick Guicheney
Montrouge, France

Doug Cameron
Adrian Stewart
Aberdeen, Scotland

□The HTHP challenge. High-temperature, high-pressure, usually deep and often corrosive wells impose the most severe constraints on drillers and well testing engineers.

High-temperature, high-pressure (HTHP) wells present special challenges to drill and test (above). Predominantly gas producers, HTHP wells may yield significant reserves in some areas. But the wells stretch conventional equipment beyond normal operational capacities. To safely meet these extreme conditions, traditional procedures have been modified and extra operational controls devised.

What constitutes HTHP is debatable. Perhaps the best definition has been coined by the UK Department of Energy:

“Wells where the undisturbed bottomhole temperature at prospective reservoir depth or total depth is greater than 300°F [150°C] and either the maximum anticipated pore pressure of any porous formation to be drilled exceeds a hydrostatic gradient of 0.8 psi/ft or pressure control equipment with a rated working pressure in excess of 10,000 psi is required.”¹

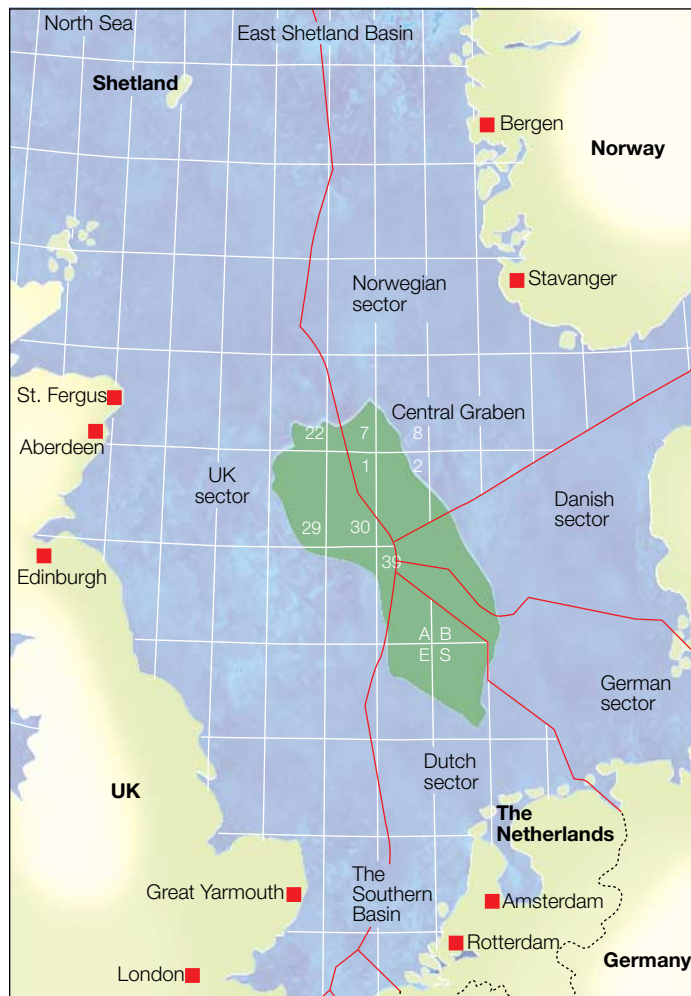
HTHP drilling is not new. In the late 1970s and early 1980s, many gas wells were

For help in preparation of this article, thanks to Willy Brandt, Sedco Forex, Aberdeen, Scotland; Andy Vigor, Schlumberger Wireline and Testing, Aberdeen, Scotland; Robbie Rounsaville and Benoit Vidick, Schlumberger Dowell, Aberdeen, Scotland.

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1. “Applications for Consent to Drill or Reenter High Pressure High Bottom Hole Temperature Exploration and Appraisal Wells: Supplementary Information to be Supplied in Addition to That Required by CSON 11,” *Continental Shelf Operations Notice No. 59*, Department of Energy, London, England, May 1990. In 1992, the UK Department of Energy (DOE) was subsumed into the Department of Trade and Industry. At about the same time, some of the DOE’s duties were transferred to the UK Health and Safety Executive.



□ **UK Central Graben. Reserves in this area may be a source of gas to replace the declining production from the UK Southern Basin. The Central Graben has the additional attraction of relatively rich condensate deposits—1 to 2 barrels of fluid per 10,000 standard cubic feet of gas. However, to fully exploit this potential, HTHP wells are required.**

Drilling Safety

Preventing and controlling influxes of reservoir fluid into the well—called kicks—are always central to drilling safety, but in HTHP wells the dangers from a kick are amplified. The volume of a HTHP gas kick remains virtually unchanged as it rises in the annulus from 14,000 to 10,000 ft [4265 to 3050 m]. From 10,000 to 2000 ft [610 m] its volume triples. But from 2000 ft to the surface, there is a hundred-fold expansion.

Put simply, a gas influx of 10 barrels at 14,000 psi becomes 4000 barrels under atmospheric conditions. As reservoir fluid rapidly expands, it forces mud out of the well—unloading—reducing mud in the well, cutting hydrostatic pressure at the formation, allowing additional reservoir fluids to enter, and ultimately causing a blowout.

Wells drilled in the Central Graben have another complication—an unpredictable and sharp increase in pore pressure over a short vertical interval, sometimes less than 100 ft [30 m]. And, while the pore pressure may rise rapidly, the fracture pressure does not. In some cases, convergence of pore and fracture pressures means that a small decrease in the mud weight of 0.5 pounds per gallon [lbm/gal] or less changes the well from losing circulation to taking a kick (next page).⁵

The difficulty of drilling in the Central Graben was highlighted in September 1988 when a blowout on the semisubmersible Ocean Odyssey resulted in fire and loss of life.⁶ Consequently, the UK Department of Energy essentially banned the drilling and testing of prospects with anticipated reservoir pressures exceeding 10,000 psi.

As a result, the UK Offshore Operators Association (UKOOA) collated the experiences of those involved in HTHP wells and drew up guidelines.⁷ In addition, in 1992, the Institute of Petroleum (IP), London, England, published a comprehensive set of recommended practices to provide information and guidance on HTHP well control activities.⁸ With these two sets of guidelines, drilling and testing has resumed.

Before an HTHP well is spudded, contingency plans are made. The maximum volume and flow rate of formation fluid, and associated peak temperatures and pressures are anticipated for a number of worst-case scenarios. Well-control hardware may then

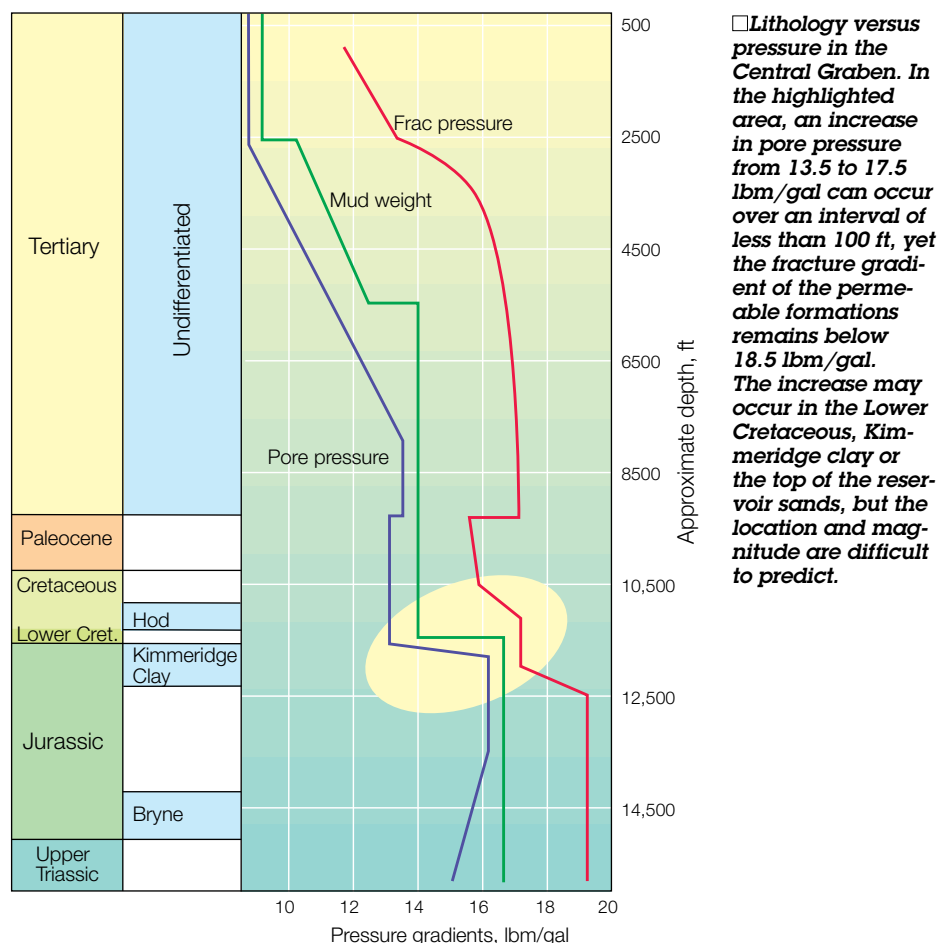
drilled in the Tuscaloosa trend, Louisiana, USA, and other southern US states. These encountered temperatures above 350°F [177°C] and pressures of more than 16,000 psi, not to mention highly corrosive environments.² When HTHP interest switched to the North Sea in the mid 80s, new hazards were introduced. The wells were drilled offshore, in extremely hostile conditions and sometimes using floating semisubmersible rigs rather than fixed jackups.

Most of the North Sea HTHP wells are situated in the Central Graben—a series of downthrown and upthrown blocks (above).³

The Central Graben contains several Jurassic gas condensate prospects at 12,000 to 20,000 ft [3660 to 6100 m], with pressures of 18,000 psi or more and temperatures of up to 400°F [205°C].

Water depth in the Central Graben varies between 250 to 350 ft [75 to 105 m]. Both jackups and semisubmersibles have successfully drilled wells in the sector, harsh environment jackups up to about 300 ft [90 m] and semisubmersibles for deeper water. Jackups offer the advantage of contact with the seabed, eliminating heave and simplifying many drilling and testing operations. On the downside, in an emergency, jackups cannot be moved off location quickly. Also, few deepwater jackups are available.⁴

This article looks at three key areas of HTHP operations in the UK Central Graben: drilling safety, casing and cementing, and testing. It also examines how North Sea experience has been used to help convert a jackup to drill demanding wells off Brunei (see “Readying a Jackup For Brunei’s HTHP Wells,” page 18).



be designed to cope with these worst cases for at least an hour, the minimum time needed to evacuate a rig.

Because the consequences of failure in HTHP wells are so great, worst-case scenarios tend to be more conservative than for normal wells. Usually, the maximum anticipated size of a kick is set at the limit of detection—often 10 to 20 barrels. In HTHP wells, many contingency plans are based on the worst case of an influx completely filling the well at reservoir pressure.⁹

When drilling with oil-base mud (OBM), there is a likelihood that gas entering the wellbore will dissolve into the mud's oil phase.¹⁰ This affects the how the kick moves up the annulus and may mask detection. Since 1986, researchers at Schlumberger Cambridge Research (SCR), Cambridge, England, have been studying the behavior of gas kicks, particularly in OBM. This work has resulted in Anadrill's SideKick software

(continued on page 20)

2. Huntoon GG: "Completion Practices in Deep Sour Tuscaloosa Wells," *Journal of Petroleum Technology* 36, no. 1 (January 1984): 79-88.
Schultz RR, Stehle DE and Murali J: "Completion of a Deep, Hot, and Corrosive East Texas Gas Well," paper SPE 14983, presented at the SPE Deep Drilling and Production Symposium, Amarillo, Texas, USA, April 6-8, 1986.
3. JM Peden: "The Central Graben—The Next North Sea Challenge," presented at the Petroleum Science and Technology Institute Seminar, The Central Graben, The Next North Sea Challenge, The Need for Joint Industry Research, Edinburgh, Scotland, September 10, 1990.
4. Low E and Seymour KP: "The Drilling and Testing of High-Pressure Gas Condensate Wells in the North Sea," paper IADC/SPE 17224, presented at the 1988 IADC/SPE Drilling Conference, Dallas, Texas, USA, February 28-March 2, 1988.
Seymour KP and Mackay A: "The Design, Drilling and Testing of a Deviated High-Temperature, High-Pressure Exploration Well in the North Sea," paper OTC 7338, presented at the 25th Annual Offshore Technology Conference, Houston, Texas, USA, May 3-6, 1993.
5. Ross I, Seymour K and Whyte B: "The Role of Jack-ups and Permanent Completions in Central Graben Exploration Drilling," presented at the Petroleum Science and Technology Institute Seminar, The Central Graben, The Next North Sea Challenge, The Need for Joint Industry Research, Edinburgh, Scotland, September 10, 1990.
6. "Ocean Odyssey Blowout Fuels UK Sector Safety Debate," *Offshore Engineer* (October 1988): 11.
7. "Procedures for High-Pressure Drilling," UK Offshore Operators Association Drilling Practices Committee, no. 2, London, England, January 1990.
Hoopingarner JB, Greif CV, Neme EE, Rodt GM and Bates TR: "Rig Modifications Meet New UK High-Pressure Requirements," paper IADC/SPE 19976, presented at the 1990 IADC/SPE Drilling Conference, Houston, Texas, USA, February 12-March 2, 1990.
8. "Well Control During the Drilling and Testing of High Pressure Offshore Wells," Model Code of Safe Practice, Part 17. London, England: Institute of Petroleum, 1992.
9. Prieur JM: "Control Aspects of Drilling High Pressure Wells," paper SPE 19245, presented at Offshore Europe, Aberdeen, Scotland, September 5-8, 1989.
10. The majority of wells have been drilled using low-toxicity OBM, which is relatively easy to design for HTHP duty. Today, more environmentally safe water-base muds (WBM) are being used. These tend to be more difficult to use in HTHP wells since they may gel or thin. WBM sometimes proves problematic because of difficulty in maintaining fluid properties. "Well Control When Drilling With Oil-Based Mud, Recent Experience in Deep Wells," *UK Department of Energy, Offshore Technology Report, OTH 86 260*, London, England: HMSO 1990.

Readying a Jackup for Brunei's HTHP Wells

Brunei Shell Petroleum has a number of offshore drilling prospects with formation pressures exceeding 10,000 psi. The first well in an HTHP campaign was spudded in August 1992 and completed in December. These wells are expected to be about 13,125 ft [4000 m] deep with bottomhole pressures greater than 14,000 psi and bottomhole static temperature peaking at approximately 300°F.

At the planning stage, one of the first considerations was choice of rig. With no suitable unit in the sector, Brunei Shell could have mobilized a North Sea rig. But the milder weather offshore Brunei does not merit such ruggedized units with high mobilization costs. A more cost-effective option was to upgrade a rig already in the sector.

Attention turned to the jackup Trident XII, operated by Sedco Forex and contracted by Brunei Shell since February 1990 (next page). Prior to modification, the rig could drill in water up to 300 ft deep, had topdrive and was fitted with the MDS computerized drilling monitoring system. But it could handle only a maximum wellhead pressure of 10,000 psi. By early January 1992, the scope of

work was defined to bring the rig up to 15,000-psi status. The plans were based largely on North Sea experience, and included:

- Replacement of the 20 ³/₄-in., 3000-psi BOP by a 21 ¹/₄-in., 5000-psi BOP—necessary because the large diameter casings were to go deeper; replacement of the 13 ⁵/₈-in., 10,000-psi BOP by a 13 ⁵/₈-in., 15,000-psi BOP; and an upgrade of the hydraulic control unit and the handling systems to accommodate the larger BOPs.
- Upgrading of the choke, kill and cement lines to handle 15,000 psi. Also replacement of choke, kill, and safety valves by equipment with 15,000-psi working pressure.
- Installation of a 15,000-psi choke pressure manifold and addition of a glycol injection unit.
- Upgrade of the MDS system to monitor HTHP parameters. To achieve this, temperature and pressure sensors were installed in strategic positions.

From agreeing on this plan to spudding the first HTHP well took only six months—including drilling a normally-pressured “shakedown” well. Rig work took three months and included an extensive program of inspection and maintenance on key rig equipment not strictly part of the high-pressure upgrade—like the topdrive, drawworks and blocks.

To meet the schedule, Sedco Forex determined equipment needs while engineering the modifications. Although time was vital—especially considering the increased delivery time on some high-pressure components—care was taken to ensure equipment was delivered with a specific quality file including traceability, interim inspection, test reports and certificates of conformance.

Some critical items were inspected and pressure tested by certification authorities. Designs for the structural modifications to the rig—like the upgrade of the BOP handling system—were also reviewed and approved by an authority, which also surveyed the work when completed.

Because this was an upgrade and not a new build, available space could rarely be increased, and never by much. For example, the 15,000-psi choke manifold weighs twice its 10,000-psi counterpart, yet had to be located at the same place and offer increased circulating options—both lines from the BOP to the choke manifold can be either a choke or a kill line.

The MDS system, which had been installed two years previously, was upgraded to monitor more parameters in real time with screens on the rig floor, and in the operator representative and toolpusher offices. New measurements included:

- Pressure and temperature upstream of the chokes, on two flow paths as choke and kill lines were dual purpose, to ensure BOP and valve elastomer ratings are not exceeded.
- Pressure and temperature downstream of the choke. Temperature monitoring enables detection of possible hydrate formation beyond the choke, indicating when glycol injection is required. Pressure monitoring ensures the 10,000-psi rating downstream of the choke manifold is not exceeded.
- Mud-gas separator (MGS) pressure. This ensures that low-pressure vessel capabilities are not exceeded. If the pressure approaches the limit, a hydraulic valve is opened to divert mud overboard.



□ The jackup Trident XII

- **MGS seal height.** This ensures that the operating capabilities of the separator are not exceeded. If this happens, mud flow is reduced or the line overboard opened.

From the beginning, a joint Shell-Sedco Forex HTHP team was established and met regularly during the six-month project. The team included a core of representatives from Brunei Shell, particularly from the drilling department, and the

Sedco Forex rig manager. Additional representatives—like geologists, equipment engineers and production engineers—attended when needed. The team's work was judged a key element in the smooth startup and safety of subsequent drilling.

The group fine-tuned technical matters of the rig upgrade—for instance, new requirements for the MGS system—and monitored the timing of project landmarks and their impact on the startup date. It established a rig commissioning list to ensure the upgrade met objectives of the initial plan and that the rig was ready to safely start the HTHP campaign.

But it did more than just ready the fabric of the rig. The group also prepared personnel who would be involved in the drilling. First, it drew up a set of HTHP drilling and well control procedures to fit local conditions and equipment. Particular attention was focused on stripping drillpipe into the well (see page 24). Second, it coordinated HTHP-awareness sessions for project personnel.

model which simulates gas kicks and may be used to plan methods of controlling HTHP wells (*below*).¹¹

Planning requires realistic data: well temperature profile, nature of the anticipated reservoir fluids, expected maximum bottom-hole pressure and pressure gradient, and rock strength and permeability. These are most often estimated using offset data—relatively plentiful in the North Sea. But where offset data are sketchy, predictive modeling may be employed. Koninklijke/Shell Exploratie en Productie Laboratorium (KSEPL), Rijswijk, The Netherlands, has developed a model to predict rock strength and pore pressure in many areas of the North Sea. KSEPL has also modified a model designed to predict wellhead temperatures in offshore production wells to estimate surface equipment temperature when controlling a kick.

Worst-case scenarios are used not only to specify equipment but also to draw up specific operational procedures, for example detailing what to do if the well takes a kick

(*next page*). Training is then used to communicate these procedures to drilling personnel. Long before drilling starts, specific HTHP training courses may be run. Once on the rig, there are prespud meetings, crew safety meetings before starting key sections of the well, preshift meetings to discuss the current situation, and regular drills to practice important techniques like closing blowout preventers (BOP).¹²

The three issues at the heart of HTHP drilling safety are kick prevention, kick detection and well control.

Kick Prevention: The best way of avoiding well-control problems is to anticipate situations known to precipitate kicks and take preventive action. Here are four examples:

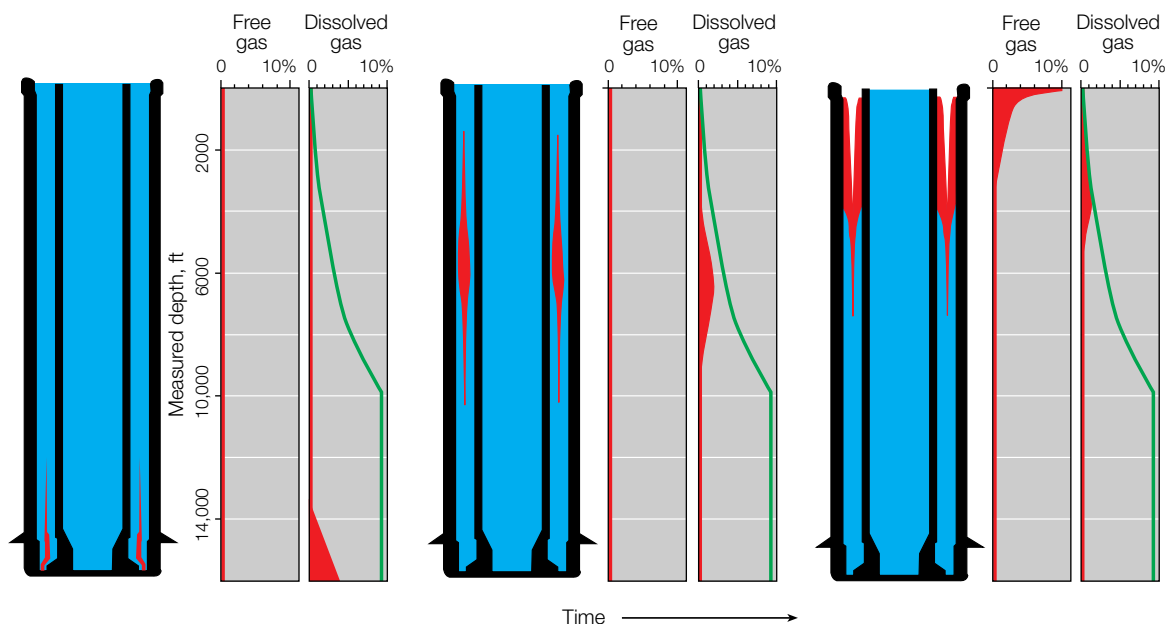
- When high-pressure formations are drilled, kicks commonly occur when the drilling assembly is being pulled out of hole. The movement of the assembly creates a piston effect reducing pressure below the bit, called swabbing. A time-consuming rou-

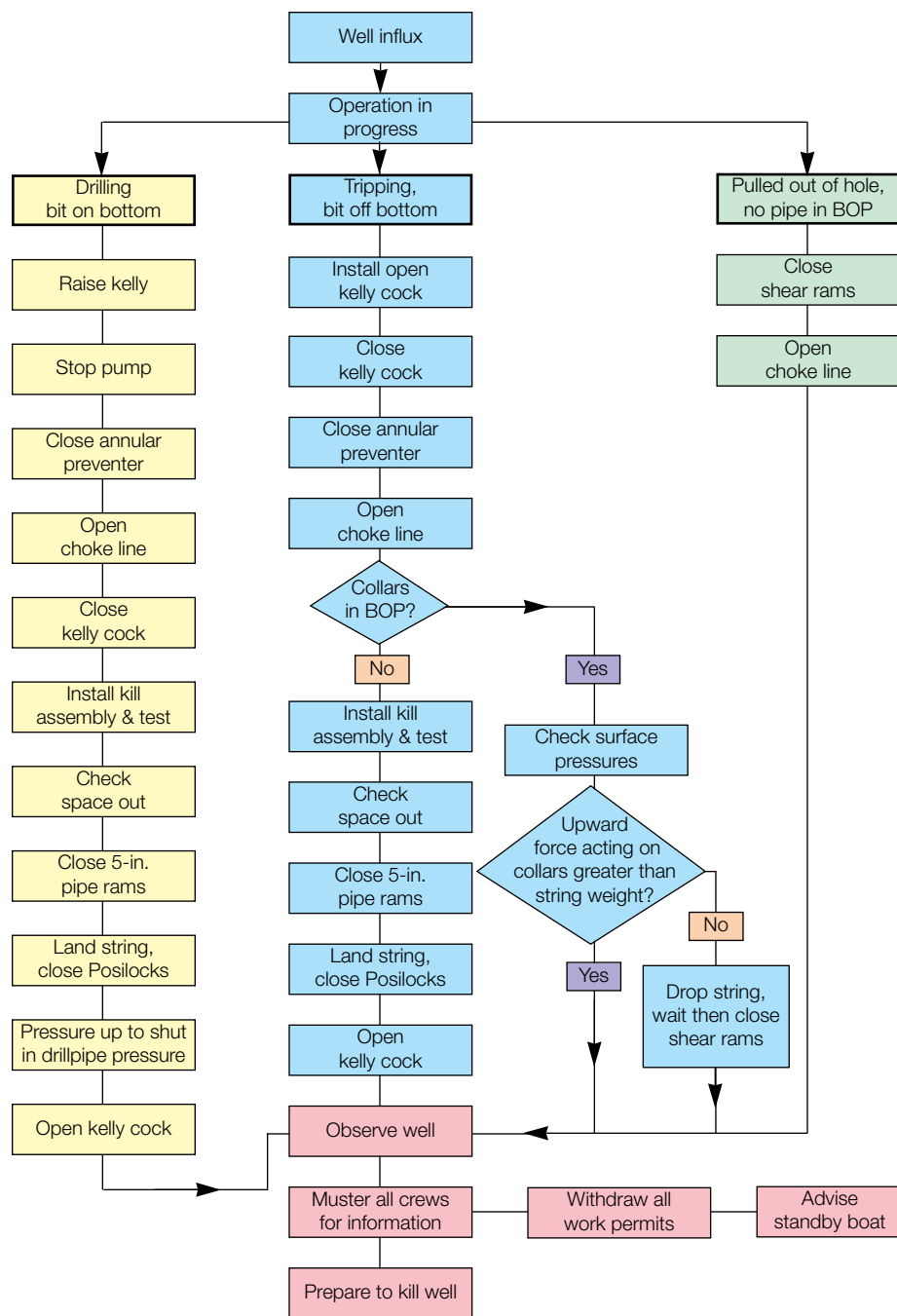
tine is usually adopted to check whether swabbing will cause an influx.

Before the assembly is pulled out of hole, the mud at the bit is circulated to surface—a procedure called circulating bottoms up. If this is free from gas, ten stands of drillpipe are pulled. The string is then run back to total depth (TD), and bottoms up are circulated. Gas in the mud is measured again, with an increase indicating swabbing.

If swabbing does cause an influx, the mud weight may be raised slightly and the string pulled out of hole more slowly. Also, circulating mud while pulling out of hole helps stop swabbing—a process made easier by topdrive. If the well is being drilled from a semisubmersible, severe vessel heave may swab the well. If heave becomes too great in stormy weather, drilling may have to stop until conditions improve.

- The combination of relatively high-viscosity mud, deep wells and small annular





□ **Generalized decision tree for controlling kicks.**

clearances leads to higher than normal friction pressure during mud circulation. At the formation, mud hydrostatic pressure and friction pressure then combine to give the equivalent circulating density (ECD). This may be designed to balance formation fluid pressure. But during a connection, mud flow stops and friction pressure is zero. With reduced ECD, small quantities of gas, called connection gas, may permeate from the formation. If bottoms-up circulation time exceeds the time to drill to the next connection point, gas that entered during the previous connection may remain undetected. Additional gas may then enter as another connection is made, significantly increasing risk of a serious kick. The safe procedure is to ensure that bottoms up has been circulated before making the next connection.

- Kicks don't occur just during drilling. Coring also causes problems. The relatively small clearance between core barrel and open hole increases the possibility of swabbing when pulling out of hole. This may be combated by limiting the amount of core cut at any one time—usually to 30 ft [10 m] or less—and pulling out of hole very slowly, checking for flow and monitoring gas in the mud.
- Tight margins between pore pressure and rock strength, as in the Central Graben, make lost circulation common, complicating well control. The normal practice on encountering losses is to pump lost circulation material (LCM) in the mud. If LCM fails to block the formation, the strategy is to pull out of hole, run back in with open-ended pipe and spot cement across the loss zone. Some slurry is squeezed into the formation and, once set, the remainder drilled out. However, in HTHP wells, the swabbing effect of pulling the bottomhole assembly out of hole prior to spotting the plug may induce a kick elsewhere in the wellbore. In this case, the only solution is to spot the cement plug

11. Leach CP and Wand PA: "Use of a Kick Simulator as a Well Planning Tool," paper 24577, presented at the 67th SPE Annual Technical Conference and Exhibition, Washington, DC, USA, October 4-7, 1992.

12. Lindsay G and White D: "The Use of a Gas Kick Simulator to Produce an Oil Based Mud Training Package," presented at the 1993 IADC European Well Control Conference, Paris, France, June 2-4, 1993.
Hornung MR: "Kick Prevention, Detection, and Control: Planning and Training Guidelines for Drilling Deep High-Pressure Gas Wells," paper IADC/SPE 19990, presented at the 1990 IADC/SPE Drilling Conference, Houston, Texas, USA, February 28-March 2, 1990.

through the bit (*below*). To make this easier, rotary drilling is favored, rather than using a downhole motor that may clog up with cement.

Kick Detection: Because no technique can guarantee kick-free drilling, influx detection remains vitally important. Traditional influx detection relies on observing mud level increases in the mud pits, or performing flow checks—stopping drilling to see if the well is flowing. Comparisons of mud flow rates into and out of the well are also used. To make detection more reliable, transfer of mud into the active system is tightly controlled and usually not allowed while drilling.

Recently, Anadrill has introduced the KickAlert early gas detection service based on the principle that acoustic pulses created by the normal action of the mud pumps travel more slowly through mud containing gas they do through pure mud. The pulses are measured as pressure variations at the standpipe as the mud enters the well and at the annulus as it comes out. If the well is

stable and no gas is entering, the phase relationship between the pressure pulses in the standpipe and annulus is constant, or changes gradually as the well is drilled deeper. When gas enters, the pulses travel much more rapidly up the annulus, dramatically changing the phase and setting off an alarm on the drillfloor.

The presence of high-pressure gas may also be indicated by changes in drilling conditions. Increases in rate of penetration, torque or mud temperature in the mud return flowline on surface may all signify the onset of a kick. Computerized monitors, like Sedco Forex's MDS rig information system and Anadrill's IDEAL Integrated Drilling Evaluation and Logging system, help drilling personnel keep track of trends and spot abnormal situations using quick-look interpretations on a drillfloor screen.¹³

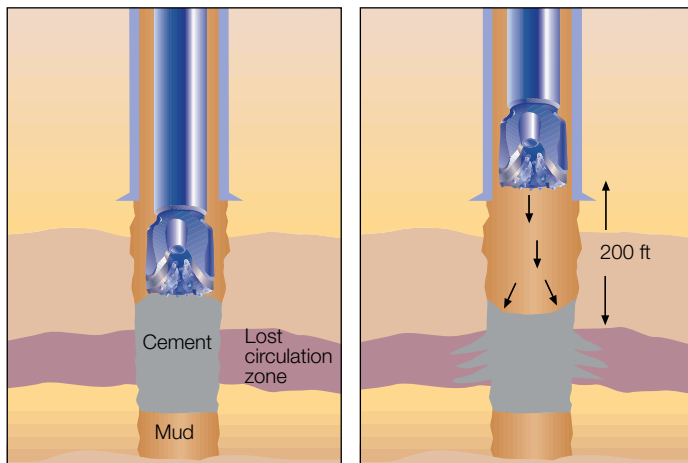
Well Control: As soon as a kick is detected, drilling is stopped and the well is shut in. The influx must then be circulated out while keeping the pressure under control (*next page*).

The BOPs are the primary means of well closure. Once a kick is suspected, the annular blowout preventer is first closed. A flexible rubber element is inflated using hydraulic pressure, and is sufficiently flexible to seal around any downhole equipment. When it has been established that no tool joints are in the way, the pipe rams are then shut, sealing around the drillpipe. Now mud can no longer return through the flowline to the shale shakers and mud pits. Instead it must travel through the choke line to the choke manifold, which is used to relieve mud pressure at surface.

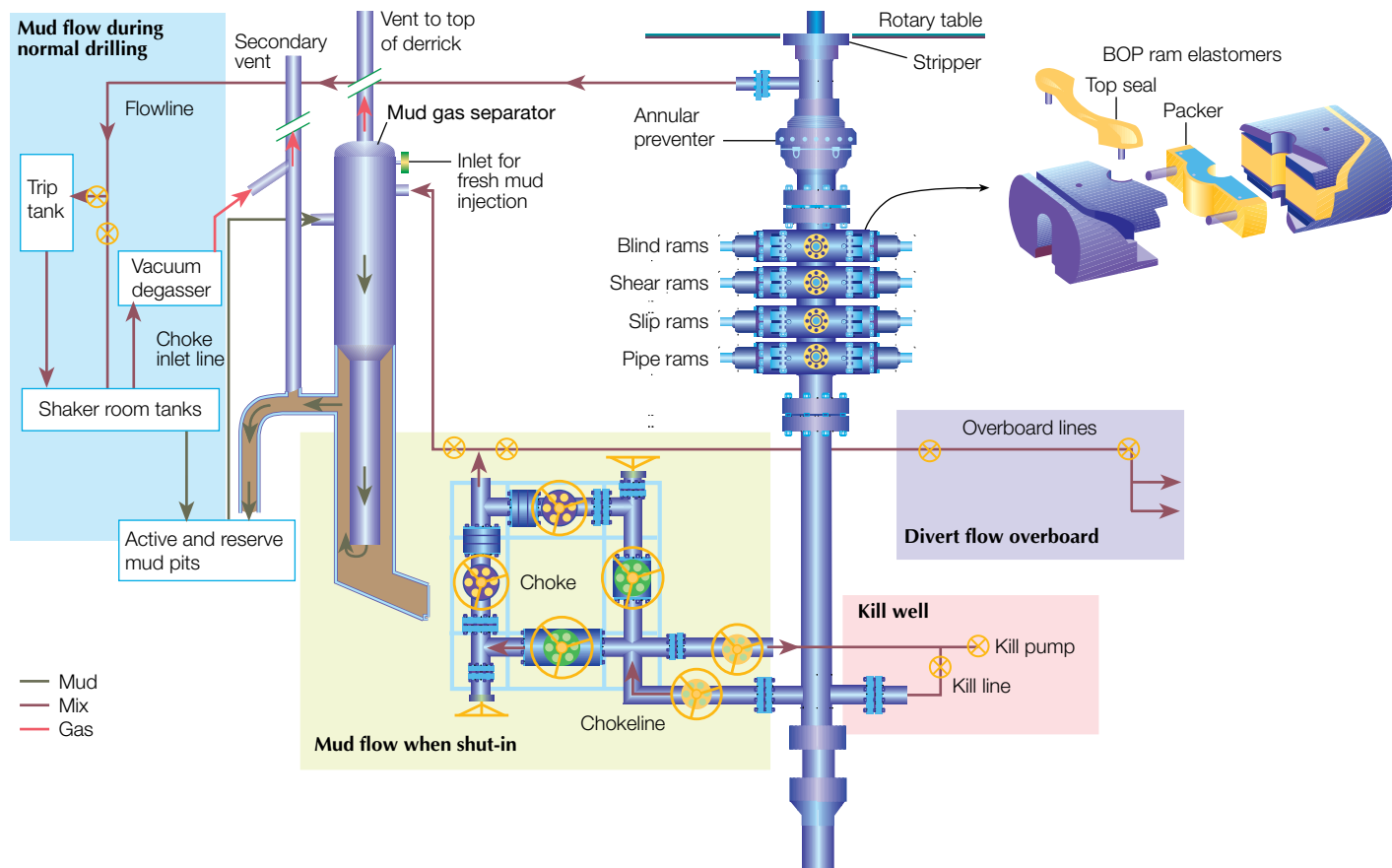
Most operators favor what is called a “hard” shut-in—closing BOPs with the choke already closed. Sometimes “soft” closure is used—the choke is closed only after the BOPs have sealed. Some believe that this reduces the hydrostatic shock to the formation, but it has the severe disadvantage of delaying closure and allowing additional formation fluid to enter the wellbore. It is also a more complex procedure, increasing the likelihood of errors.¹⁴

The capacity of a BOP to resist pressure depends on the elastomeric seals inside the rams and their likelihood of not being extruded. As temperature increases, extrusion becomes more likely. Seals may have to withstand prolonged temperatures that top 400°F [205°C]—beyond the limits of ordinary components. Finite-element analysis has been used to identify which areas of the BOPs are most affected by heat and which seals need special elastomers rated to 350°F.¹⁵ Sometimes, special BOP temperature monitors are used to ensure these extended limits are not breached. However, high-temperature elastomers are harder than their low-temperature counterparts and may not seal at ambient temperature, making surface pressure tests difficult.

Once the BOPs and choke are closed, pressure builds in the annulus and drillpipe. The maximum drillpipe pressure is used to calculate bottomhole pressure, which is used to plan the kill strategy. Well-kill strategy also takes into consideration the drilling operation underway during the kick.¹⁶



□ **Spotting a plug without cementing the pipe in the hole.** With the bit 100 to 200 ft above the loss zone, preferably inside the previous casing shoe, 5 barrels of mud-base oil, 20 barrels of spacer, 50 to 100 barrels of cement and a further 20 barrels of spacer may typically be pumped until the base oil reaches the bit. The annular BOP is closed and the plug squeezed until the top of cement reaches 50 ft above the top of the loss zone. The last 10 barrels are displaced down the annulus to ensure the bit is free of cement. While the cement is setting, the pipe is worked up and down with the annular preventer closed. To avoid plugging the bottomhole assembly due to gelation, sedimentation or premature setting, extensive tests are needed to ensure that the slurry has uniform, predictable properties at downhole conditions.



□ **The well-control layout.** Normally, drilling mud returns to the pits via the flowline and the shale shakers. If the well takes a kick, the BOPs shut off flow, directing it through the choke line to the choke manifold and then to the mud-gas separator (MGS).

Inside the MGS, gas is safely vented and the mud returned to the mud system. Fluid in the MGS acts as the only barrier preventing gas from forcing its way into the mud room. Separator seal pressure is reduced as heavy mud is diluted by the relatively light hydrocarbons from the influx. In some MGS systems, fresh mud may be circulated down the seal leg, displacing the hydrocarbons and ensuring a tight seal. BOPs have a combination of annular preventer and rams—the exact choice of elements varies. At high temperature, normal elastomers that seal inside the rams may soften and be extruded. For HTHP drilling, harder high-temperature elastomers are usually used.

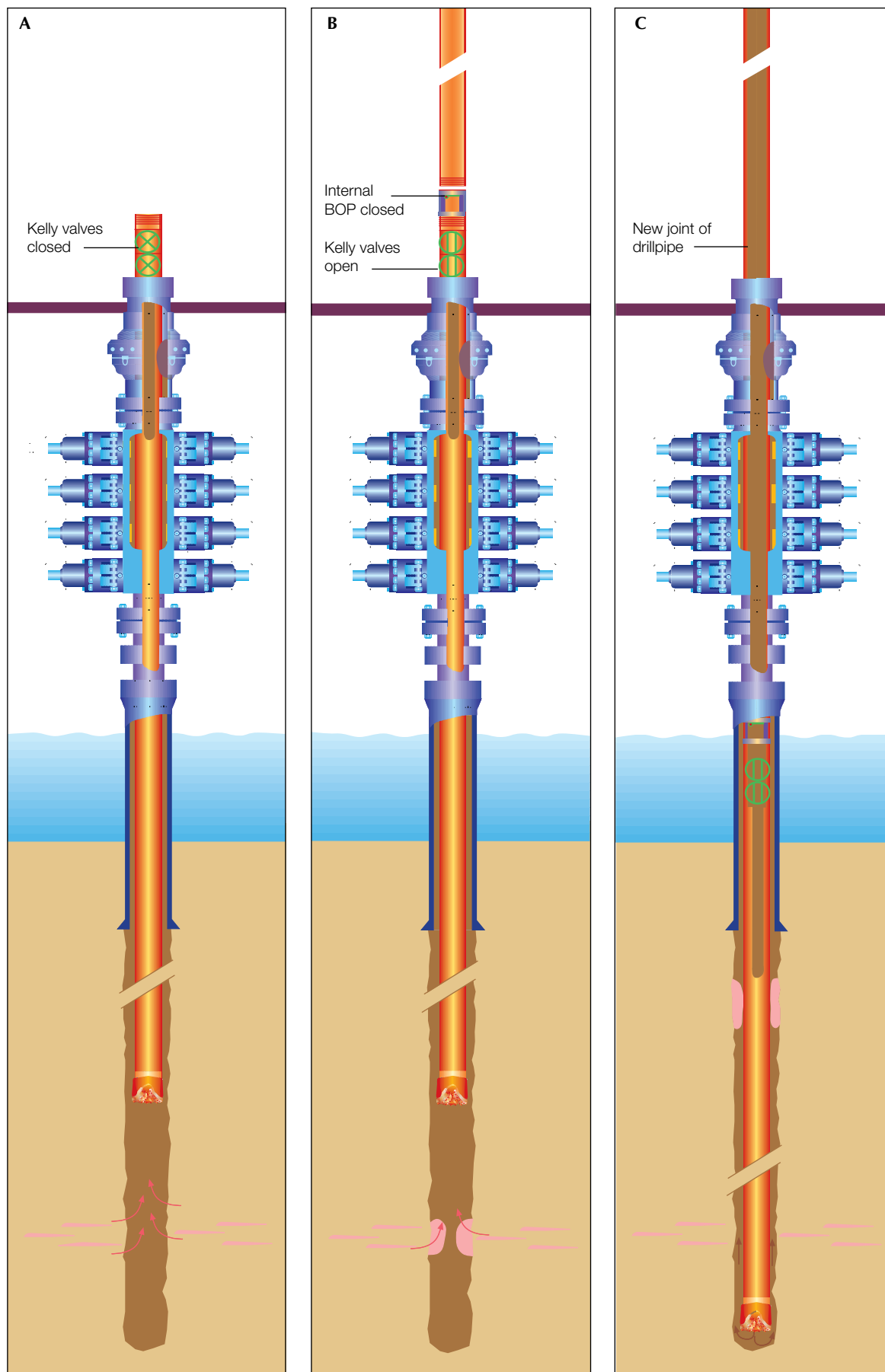
If the kick occurs during drilling, weighted mud—either from a premixed or specially prepared supply—may immediately be pumped down the drillpipe. The formation fluid influx is gradually displaced up the annulus, expanding as hydrostatic pressure decreases. At surface, the mud-influx mixture travels to the choke manifold via the choke line and has its pressure reduced by the choke. The well is slowly brought under control by carefully selecting mud weight and choke opening.

It is vital that the surface drilling and pumping equipment withstands the pressures during the kill—for example, the kelly or topdrive are usually rated to only 5000 psi. The surface pressure during the kill is estimated by adding the shut-in drillpipe pressure to the friction pressure of the fluid

as it is pumped into the well. Friction pressure is routinely measured by the drilling crew at the start of every 12-hour shift. If calculations show surface limitations will be breached, a kill assembly rated to 15,000 psi must be temporarily installed after the well has been shut in. Two valves in the drillstring just below the kelly or topdrive—called surface valves or kelly cocks—are closed to seal inside the drillstring allowing removal of the topdrive or kelly and installation of the kill assembly.

Controlling a kick while the drillstring is being pulled out of hole is less straightforward. Reservoir fluid enters below the bottom of the drillstring and cannot be circulated out of the well until drillpipe is run back in hole below the kick. Running in drillpipe through a closed BOP is called stripping and requires careful coordination of several critical operations (*next page*). Once stripped back in hole, a conventional

13. Weishaupt MA, Omsberg NP, Jardine SI and Patterson DA: "Rig Computer System Improves Safety for Deep HP/HT Wells by Kick Detection and Well Control Monitoring," paper SPE 23053, presented at the Offshore Europe Conference, Aberdeen, Scotland, September 3-6, 1991.
14. Jardine SI, Johnson AB, White DB and Stibbs W: "Hard or Soft Shut-in: Which is the Best Approach?," paper SPE/IADC 25712, presented at the 1993 SPE/IADC Drilling Conference, Amsterdam, The Netherlands, February 23-25, 1993.
15. McWhorter DJ: "High-Temperature Variable Bore Ram Blowout Preventer Sealing," paper OTC 7336, presented at the 25th Annual Offshore Technology Conference, Houston, Texas, USA, May 3-6, 1993.
16. Jardine SI, White DB and Billingham J: "Computer-Aided Real-Time Kick Analysis and Control," paper SPE/IADC 25711, presented at the 1993 SPE/IADC Drilling Conference, Amsterdam, The Netherlands, February 23-25, 1993.



□ Stripping drillpipe into the well. After the annular preventer in the BOP stack is closed around the drillstring, new joints of pipe are added to the string and forced through the preventer into the well. While this is happening, the internal pressure of the drillpipe must be controlled. Two kelly cocks or surface valves are always included in the drillstring, just below the topdrive or kelly. For stripping, they are closed, sealing inside the drillpipe, then the elevators are removed (A). A set of internal BOPs is fitted inside the pipe. This acts as a one-way valve holding pressure from below while allowing flow to pass from above. In this way, the kelly valves may be reopened and joints of pipe added without exposing the drillfloor to a flowing well (B). Sufficient pipe is added until the bit is below the influx, which may then be circulated out (C).

This process must take into account the increased volume of the string as joints are added, and the increased volume of the reservoir fluid as it travels up the well. Careful control of the choke is needed to bleed off calculated volumes of mud and maintain the right backpressure.

kill operation may be started and the influx circulated to the choke manifold.

For HTHP drilling, the choke manifold is typically rated to 15,000 psi, while equipment downstream of the choke is rated to 5000 psi, sometimes 10,000 psi. Redundancy demands no fewer than two flow paths, so the manifold comprises at least two chokes. A large pressure drop across the choke may result in adiabatic cooling of the fluid on the low-pressure side, and cooling leads to development of hydrates and plugged lines. To prevent this, glycol or methanol must be injected upstream of the choke. Remote sensing of upstream and downstream choke temperature and pressure enables monitoring of potential hydrate formation.

Once fluid pressure has been reduced by the choke, returns are routed in one of two directions: diverted overboard or to the mud-gas separator—also known as the poor-boy separator. Flow is normally diverted overboard only in an emergency—for example, a blocked line.

The MGS is traditionally employed to vent small volumes of free gas in the mud, preventing frothing and reducing the load on the subsequent vacuum degasser. Inside the MGS, internal weirs allow the gas to separate from the mud and be vented (page 23). A small hydrostatic head of less than 15 psi prevents gas from forcing its way through the MGS into the mud tanks. For HTHP duty, pressure sensors warn when the gas pressure threatens to exceed the hydrostatic head so that the well may be shut in until the liquid seal is reestablished.¹⁷

In some cases, the influx may be so large, the anticipated pressure so high or the concentration of hydrogen sulfide (H₂S) so great, that circulating the reservoir fluid to surface is not considered safe. In these rare cases, the only alternative is to squeeze the fluid back into the formation—a procedure called bullheading.

Bullheading presents additional challenges. It may involve considerably higher surface pressures and pump rates than circulation and may pressure up or fracture the formation. Also, the fractured formation may not be the source of the kick, creating the conditions for an underground

blowout—reservoir fluid flowing into another formation. Once bullheading starts, it may be difficult to keep track of what fluids are in the well and where they are. Furthermore, the operation may burst casing that has been weakened during drilling.

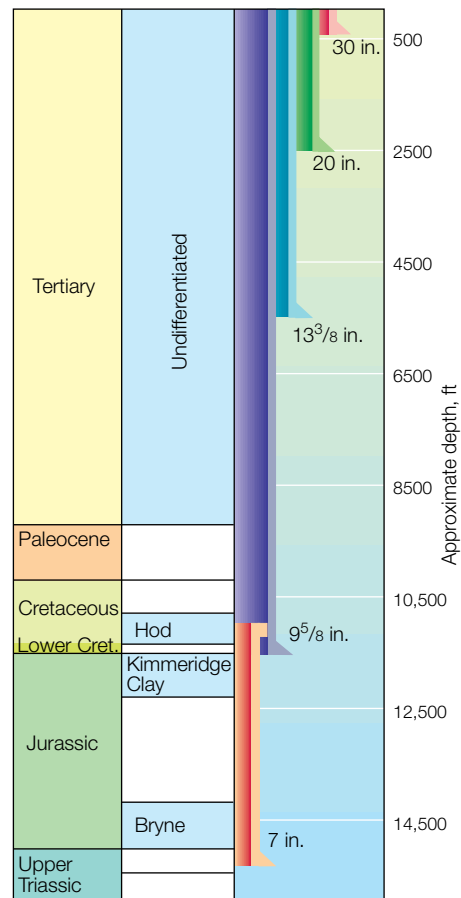
Casing and Cementing

In Central Graben wells, choosing the location of the intermediate—usually 9⁵/₈-in.—casing shoe is crucial. Ideally, casing must be set above the high-pressure reservoir and just below a zone of weak Hod chalk (right). If it is set too high, the weak formation will be exposed to subsequent high pressure, and the only solution is to set a short, perhaps less than 100 ft, 7-in. drilling liner. This has the undesirable effect of reducing the diameter of further drilling.

Consequently, the shoe is usually set at the bottom of the Hod chalk, in the Lower Cretaceous clays or in the Kimmeridge clay just above the reservoir. But finding the casing point is not easy—vertical seismic profile surveys may be employed.¹⁸ As drilling approaches the likely casing point, it is intermittently halted, bottoms up circulated and cuttings examined by a geologist or micropaleogeologist.

Pressure is a key consideration when designing the casing string. The 9⁵/₈-in. casing is often designed to withstand complete evacuation to atmospheric pressure with reservoir pressure in the annulus between open hole and casing. Given the high pressures, heavy-weight casing is usually required throughout the string.

H₂S is another consideration. At high temperatures, the corrosive gas does not affect steel. But when temperatures fall below about 185°F [85°C] higher up the well, casing may be prone to attack. To combat this, special-grade steel is required. This may reduce casing inside diameter preventing passage of an 8¹/₂-in. bit. The solution favored by many North Sea operators is to use thick-walled, special-grade steel 9⁷/₈-in. or even 10³/₄-in. casing higher up the well tapering to 9⁵/₈ in. as the temperature



In search of the ideal casing point. In some cases, the preferred place for the 9⁵/₈-in. casing shoe is in the upper section of the Kimmeridge clay, which is sometimes as little as 50 ft [15 m] thick in total. But there are potential high-pressure sand lenses within the clay. This may mean setting the shoe in the fractured Hod chalk. In this case, the aim is to have the shoe at the bottom of the zone, where fractures are least prevalent.

17. Low E and Jansen C: "A Method for Handling Gas Kicks Safely in High-Pressure Wells," paper SPE/IADC 21964, presented at the 1991 SPE/IADC Drilling Conference, Amsterdam, The Netherlands, March 11-14, 1991.

18. Meehan R, Miller D, Haldorsen J, Kamata M and Underhill B: "Rekindling Interest in Seismic While Drilling," *Oilfield Review* 5, no. 1 (January 1993): 4-13.

increases and H₂S attack ceases to be a danger.¹⁹ However, if the design is too conservative, the casing string may become so heavy that the rig cannot bear the hook load to run the casing.

Once the casing string has been run, the shoe must be cemented to resist the high reservoir pressure that will be encountered almost as soon as the next section of drilling starts. Location of the top of cement (TOC) of the 9⁵/₈-in. casing is sometimes an issue. In normal wells the TOC is usually above the previous casing shoe, with fluid trapped in the annulus above the TOC. When HTHP wells are drilled, hot mud passing up the drillpipe-casing annulus heats fluid in the casing-casing annulus, causing it to expand. For a subsea-HTHP well, the pressure has no escape and it can burst or collapse the casing. For this reason, the TOC for 9⁵/₈-in. casing in a HTHP well is sometimes kept below the 13³/₈-in. shoe to allow annular pressure to dissipate into the formation.

In most HTHP wells a 7-in. liner is run, although in some cases it may be possible to cement a 7-in. casing to surface. In either case, the cement job must isolate the high-pressure zones to facilitate well testing. This requires good cementing practices and a carefully designed slurry.

Mud removal is vital in achieving strong cement bonding to the formation and casing, and sealing against high pressure. Even small quantities of contaminant in the cement slurry compromise the final setting strength (*above, right*). Spacers reduce contamination, but high temperatures may thin or destroy spacer polymers causing weighting agents to settle. An emulsified Dowell spacer or XC polymer, both weighted by hematite, have been successfully employed.

Neat Class H Cement (16.5 lbm/gal)		
Mud contamination (% by volume)	Compressive strength (psi at 170° F)	
	8 hr	16 hr
0	4547	5862
5	3512	5300
10	2519	4538
20	2378	2331
50	245	471

□ **Effects of mud contamination on slurry strength after 8- and 16-hour setting times.**

The tight pressure constraints found in HTHP wells mean that the traditional density hierarchy—cement heavier than the mud with an intermediate spacer—is difficult to achieve without exceeding formation fracture pressure. A viscosity hierarchy is also desirable, but when cement is thicker than mud, the friction pressure may increase beyond the limit. This emphasizes the importance of other good drilling and cementing practices: drilling an even well-bore, circulating and conditioning the mud correctly, and centralizing the casing.²⁰

Cement slurry rheology is usually designed to give the best flow regime for mud removal using allowable pump rates. Although turbulent flow is normally preferred, pump rate restrictions often result in the use of effective laminar flow. A major constraint on pump rate in HTHP wells is the high friction pressure in the 7-in. liner annulus. To predict friction pressures and keep ECDs below the formation fracture gradient, a Fann Model 70, HTHP viscometer is used to measure slurry rheologies at up to 500°F [260°C] and 20,000 psi. These data may then be fed into design software like Dowell's CemCADE service.²¹

Besides rheology, HTHP cement slurries have many other design considerations:

- Some cement slurries in HTHP wells require long setting times. Depths of more than 15,000 ft [4575 m], high friction pressures and low fracture gradients mean long pumping times—in some cases 7 hours or more. Bottomhole static temperatures (BHST) are high and accurate estimation of the bottomhole circulating temperature (BHCT) is vital to ensure that the slurry sets at the right time.

BHST—usually defined as the temperature 24 hours after the last circulation—is

measured during logging and converted into BHCT using American Petroleum Institute (API) conversions.²² Software temperature models are also available. Dowell's CemCADE temperature simulator calculates BHCT versus time and depth, taking into account mud properties, well geometry and deviation, borehole geology, mud temperature in and out of the well, and the pump rate (*next page*).

Temperature probes have also been used. Heat-sensitive paper is encased in small spheres and pumped with the mud. Recovery varies from 10 to 50%, but once at surface, a color change in the paper is used to determine the maximum temperature the sphere encountered.

Retardation is complicated by the need to design a slurry that may encounter a shoe up to 70°F [39°C] hotter than the liner top. Yet good cement is required at both locations. In general, if the static temperature at the top of the liner is less than the circulating temperature at the shoe, the slurry will set satisfactorily in both locations. However, if the situation is reversed, there can be difficulties formulating a slurry to set at both temperatures. This requires a retarder that is not too temperature-sensitive.

- In gas zones with a low overbalance, there is the risk that high-pressure gas will enter the cement during hydration and create large channels. Elsewhere, loss of fluid into the formation reduces the slurry liquid-to-solids ratio, changing rheology, density and setting time. Resistance to gas migration and fluid-loss control are often handled using latex additives. This is also the case in HTHP wells. In some cases, gas-tight, high-temperature slurries have been designed using latex additive and Class H cement rather than the more usual Class G.²³ At these extreme conditions, the Class H slurries show longer natural thickening times, advantageous rheologies and a right-angle set—a rapid transition to setting rather than a gradual one.
- Set cement must exhibit good compressive strength at the shoe and liner hanger. Strength may deteriorate with time, something that becomes more likely once the expected BHST exceeds 225°F [107°C]. Hottest North Sea wells drilled so far have

exhibited BHSTs of around 400°F, so cement recipes always include silica flour, which prevents a loss of strength and increase in permeability that may otherwise occur in set cement over time.

- Narrow margins between pore pressure and fracture pressure mean that the hydrostatic pressure during cementation is crucial. To achieve the correct density, a weighting agent—usually hematite—is required. In the field, a 100-barrel batch mixer is often used to produce a homogeneous slurry with a very accurate density.
- Solids in the slurry must remain in suspension. This is sometimes difficult to achieve. For example, weighting agents are obviously heavy and need to be supported to avoid settling. However, to achieve the desired flow properties the slurry may need to be thinned. But if it is too thin, settling may occur, threatening the quality of the set cement.

To balance design factors like these, extensive laboratory testing is required to ensure that the slurry exhibits the right properties at downhole conditions. Tests should also reflect field mixing technique. Batch-mixing is usually simulated by stirring the slurry in a consistometer for the appropriate period to impart an appropriate mixing energy.

Once the 7-in. liner is cemented, casing pressure tests simulate losing control during well testing and exposing the entire string to formation pressure. Tests are generally carried out using a retrievable packer set above the theoretical top of cement in the annulus. This avoids creating microannuli, tiny conduits between cement and casing that form when the casing expands under pressure and compacts the annular cement. But the tests use mud, creating a different fluid gradient in the well than would be found with gas. To combat this, the packer is progressively moved up the well in a series of tests to reproduce the worst case of a gas-filled well.

Testing

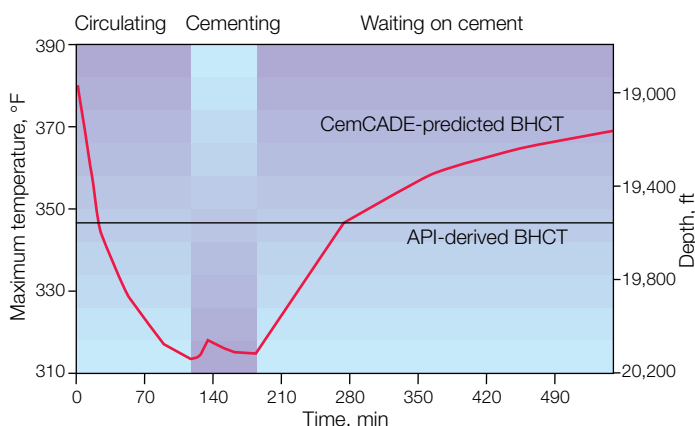
Cores are taken and logs run where possible and used to decide whether and where to test. Coring may be limited by its propensity to swab the well and cause kicks. For logging, the tolerance of all standard wireline logging tools to high temperature may be boosted by thermal insulation.²⁴ Wireline must also be protected. Choice of insulation material and armor is influenced by depth, wellhead pressure, bottomhole temperature and pressure, the possible presence of H₂S and job duration. A dedicated suite of tools and wireline reel is often prepared, tested and certified for HTHP use.

Once cores and logs have indicated the presence of hydrocarbons, a well test is needed to determine parameters like reservoir extent and permeability, and to sample reservoir fluid. In almost all cases, a cased-hole drillstem test is used.²⁵ The well is normally shut in using a downhole valve and flow is controlled at surface using a choke

manifold. Periods of flow and shut-in allow collection of data like flow rate and pressure changes. In HTHP tests, fluid samples are usually gathered at surface during a flow period (see “An HTHP Test in Depth,” page 30).

The rates and pressures experienced during testing HTHP wells are prodigious. One test by Ranger Oil Ltd. in the Central Graben using a jackup rig resulted in 44 MMscf/D of gas and 4400 B/D of condensate. The maximum recorded tubing-head pressure was 12,500 psi, the bottomhole temperature was 386°F [197°C] and the surface temperature reached 300°F—even though surface equipment was cooled with water.²⁶ Equipment has been designed and built to test 20,000 psi and 400°F formations.

Well-control equipment used during drilling is designed to handle reservoir fluids for relatively short periods. During a test, the surface equipment must cope with long flow periods. Where possible, elastomers



□ **Predicting maximum bottomhole circulating temperature.** This plot shows the magnitude and depth of the maximum BHCT at any given time. Traditionally, API conversions have been used to transform bottomhole static temperature to bottomhole circulating temperature. This gives a single value. Increasingly, software systems like the CemCADE temperature model are used to simulate cement jobs and show how temperature varies with time and depth.

19. Krus H and Prieur JM: “High-Pressure Well Design,” *SPE Drilling Engineering* 6 (December 1991): 240-244.

20. Bittleston S and Guillot D: “Mud Removal: Research Improves Traditional Cementing Guidelines,” *Oilfield Review* 3, no. 2 (April 1991): 44-54.

21. Vidick B and Acock A: “Minimizing Risks in High Temperature/High Pressure Cementing: The Quality Assurance/Quality Control Approach,” paper SPE 23074, presented at the Offshore Europe Conference, Aberdeen, Scotland, September 3-6, 1991.

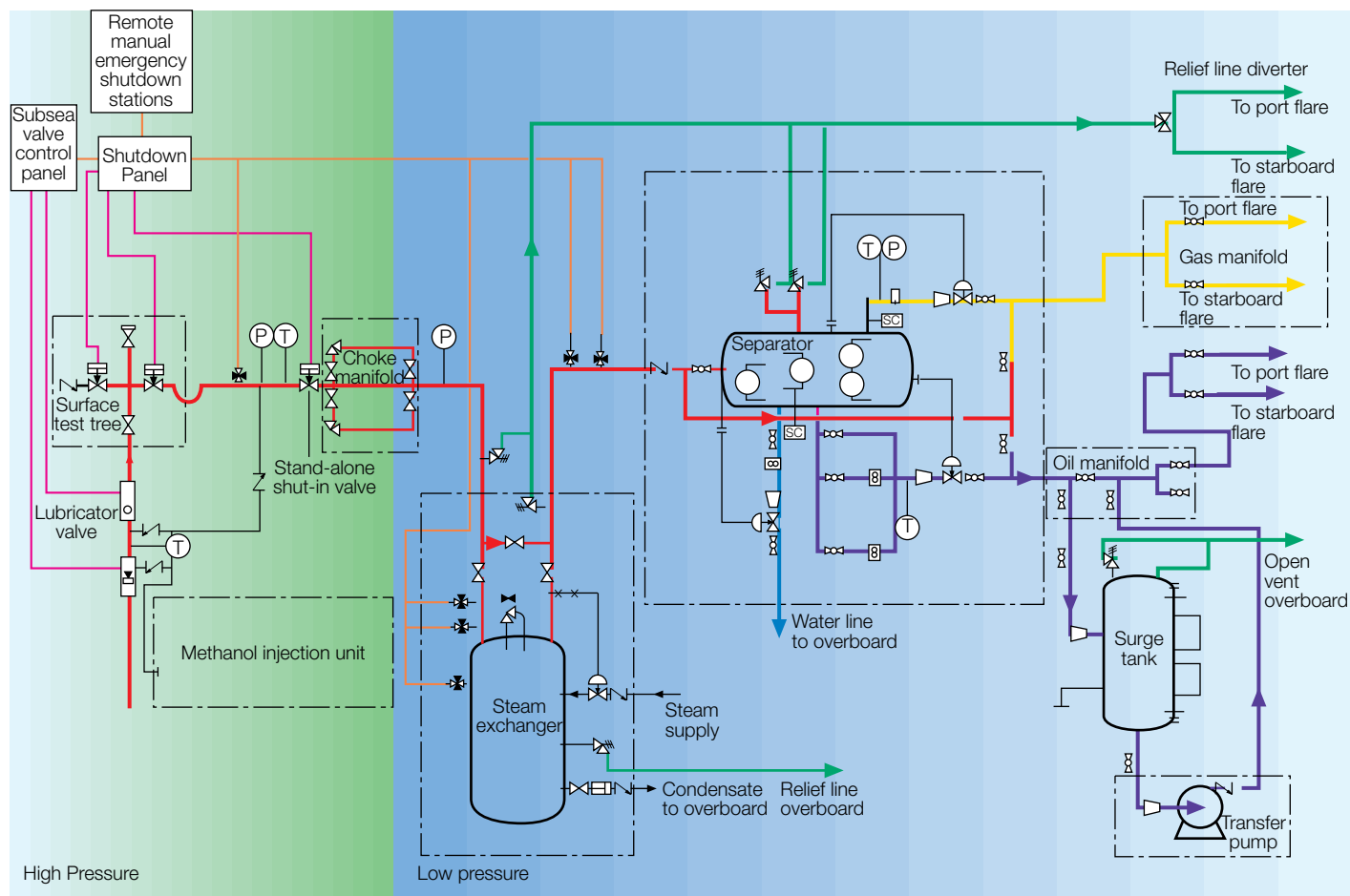
22. *API Specification for Materials and Testing for Well Cements*, 5th ed. Dallas, Texas, USA: American Petroleum Institute, 1990.

23. Cement is traditionally divided into classes defined by the API that broadly describe the proportions of the different chemicals making up the compound and their particle size distribution.

24. A universal Dewar flask protects logging tool electronic cartridges. For example, if a CSI Combinable Seismic Imager tool is put in an oven at 415°F [212°C] for four hours, its internal temperature rises to about 350°F. However, if the tool has been protected by UDF equipment, its internal temperature increases only to about 200°F [93°C], comfortably within its operating specifications. Insulation increases tool outside diameter from 3 3/8 to 3 5/8 in.

25. Vella M, Veneruso T, Le Foll P, McEvoy and Reiss A: “The Nuts and Bolts of Well Testing,” *Oilfield Review* 4, no. 2 (April 1992): 14-27.

26. Ford J, Peden J and Rae G: “A Review of Completion Design for Deep, Hostile, High Pressure, High Temperature Wells,” presented at the Petroleum Science and Technology Institute Seminar, The Central Graben, The Next North Sea Challenge, The Need for Joint Industry Research, Edinburgh, Scotland, September 10, 1990.



- Hydrocarbon process line
- Relief line
- Separator oil line
- Separator gas line
- Pneumatic signal
- Hydraulic signal
- T Temperature monitoring
- P Pressure monitoring

□ **Simplified process and instrumentation diagram of the surface testing system. Well fluid flows through the surface test tree to the choke manifold where pressure is reduced by the choke from 15,000 psi to about 1000 psi. If limits are breached, the flow may be shut in at the subsea valve, surface test tree or stand-alone isolation valve. To prevent hydrate formation, methanol or glycol may be injected upstream of the choke and the fluid heated by the steam exchanger downstream.**

are replaced by metal-to-metal seals, removing the temperature limitation of test equipment. Surface and subsea equipment are monitored using temperature and pressure sensors that report back to a real-time monitoring system, which initiates the emergency shutdown (ESD) system if limits are breached. In addition, the number of downhole test tools and the number of operations they perform are kept to a minimum.

Because of the extreme conditions, HTHP test planning and equipment selection have to be meticulous, and the personnel performing the tests highly trained. With information from offsets, the first task is to anticipate likely maximum values for several key parameters like shut-in tubing-head pressure

and wellhead temperature, downhole temperature and pressure, and flow rate. These maxima are used to select equipment with the necessary operating capabilities. If these capabilities are exceeded, the test must stop or the test objectives be reviewed. In establishing the maxima, attention must be paid to data collection. For example, to acquire the correct data, the test will have a minimum flow period, and the length of this period will then affect temperature of seabed equipment.

Next, the individual safety requirements of each component are determined—for example, pressure relief valves and temperature monitors. Then the components are considered as part of the whole test system, allowing elimination of any redundant safety devices.

When the equipment package is determined, a piping and instrumentation diagram may be prepared, which specifies all the equipment, piping, safety devices, and their operating parameters (above). A layout diagram highlights the positions of key well test equipment making sure that they interface with existing rig ESD systems and fit into limited space. Safety checks and analyses are carried out according to API recommendations.²⁷ Procedures are established for key operations like perforating the well, changing chokes or pressure testing all equipment. Contingency plans are made to cope with a range of possible incidents: downhole leaks or failures, surface leaks, a deterioration in the seastate or weather, or the formation of hydrates at surface.²⁸

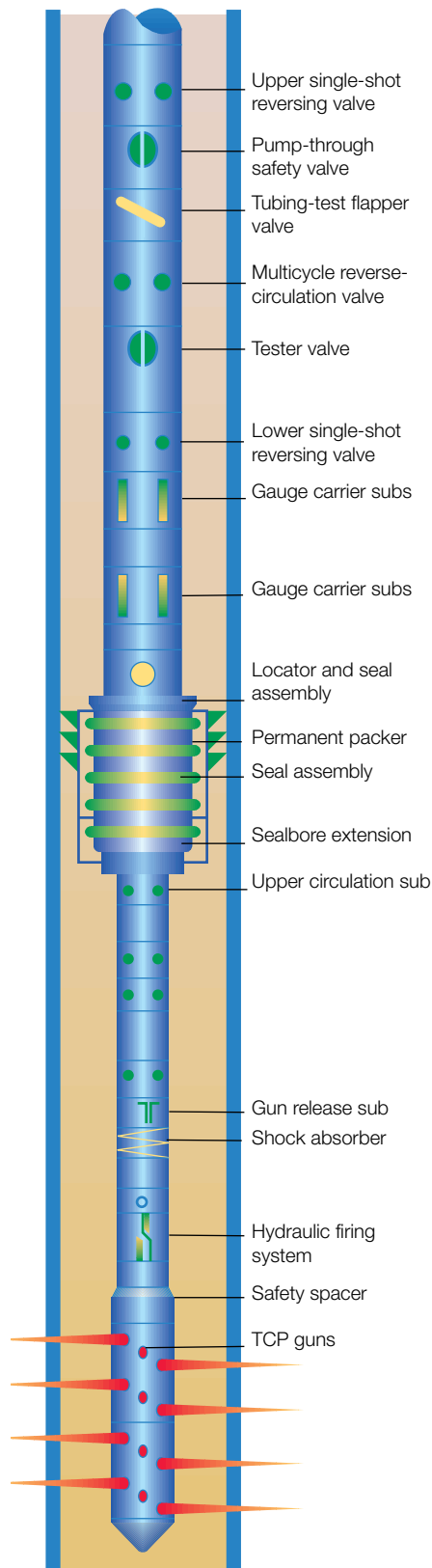
This information is submitted to an independent certifying authority that must approve the plans before the test can proceed. In addition, inspection certificates are checked before each piece of equipment is dispatched offshore. Finally, the certifying authority has to approve the rig up.

Test equipment and operations may be divided into three sections: downhole, sub-sea and surface.

Downhole Equipment: Sealing off the candidate formation requires a packer. During an HTHP test, differential pressures across the packer may exceed 10,000 psi. For this reason, permanent packers are usually chosen, rather than the retrievable packers used in lower pressure tests. With wireline (or very occasionally drillpipe), the packer is installed complete with a sealbore, and a seal assembly is then run with the test string to seal into the packer. The seal assembly is usually about 40 ft long to allow for the thermal expansion of the test string as hot reservoir fluid flows.

Perforating with wireline guns is generally avoided during HTHP tests, so tubing-conveyed perforating (TCP) is preferred. Unlike wireline perforating, TCP allows the reservoir to be perforated underbalanced and immediately flowed through the test string.²⁹ Because the guns will spend hours in the well prior to firing, high-temperature explosive is used. In most cases, the TCP guns are run as part of the test string, rather than hung off below the packer. This reduces the time that the explosives spend downhole and allows the guns to be retrieved in case of total failure.

In most HTHP wells, TCP guns are fired using a time-delay, tubing-pressure firing mechanism. Tubing pressure initiates the firing process, but the pressure is then bled down to underbalance pressure. The guns fire after a preset delay, long enough to achieve underbalanced conditions. A secondary firing system is usually included in case the primary system fails.



Although the number of downhole tools is reduced to a minimum, HTHP tests still require a number of components to allow downhole shut-in, pressure testing of the string, reverse circulation to remove hydrocarbons from the string prior to pulling out of hole, and downhole measurement of pressure changes (*left*). Sometimes to simplify the test procedure surface shut-in is substituted for downhole shut-in. However, this introduces wellbore storage—the spring effect of the column of fluid in the well below the surface valve that must be accounted for by data analysis and usually necessitates longer shut-in periods.

In most cases, test tools are operated using annular pressure. The condition of the fluid in the annulus, usually drilling mud, plays a critical factor. High-density, high-solids drilling fluid may plug pressure ports and reduce tool reliability. Solids may also settle, potentially sticking the test string. The effects on heavy, water-base mud of being static in a hot well have been thoroughly

□ Downhole test string.

- **Upper and lower single-shot reversing valves**—opened using annular pressure to communicate between the annulus and the tubing and allow reverse circulation. Once open, these may not be closed.
- **Pump-through safety valve**—closes when the annulus is pressured to a predetermined value (usually significantly higher than the pressures used to cycle the tester valve). It is a one-shot tool for emergencies only.
- **Tubing-test flapper valve**—holds pressure from above to enable tubing and tools to be pressure tested but allows fullbore flow from below. The flapper is permanently locked open during testing using annular pressure.
- **Multicycle reverse-circulation valve**—in some cases, a recloseable recirculating valve is included in the string. It is opened by cycling tubing pressure a preset number of times and closed by circulating through it at a preset rate.
- **Tester valve**—annular pressure opens and closes the ball valve, allowing flow and buildup periods during the test. The valve also acts as an additional emergency barrier to flow.
- **Pressure gauges in carrier subs**—gauge reliability at high temperatures is major bugbear. At 350 °F, most electronic gauges are at the limit of endurance. Combinations of high-accuracy electronic and less accurate mechanical gauges, with a limit of 500 °F, are often run.

27. *Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms*, API Recommended Practice 14C, 4th ed. Washington, DC, USA: American Petroleum Institute, 1986.

28. Davidson AR, Prise G and French C: "Successful High-Temperature/High-Pressure Well Testing From a Semisubmersible Drilling Rig," *SPE Drilling & Completion* 8, no.1 (March 1993): 7-13.

29. Cosad C: "Choosing a Perforation Strategy," *Oilfield Review* 4, no. 4 (October 1992): 54-69.

An HTHP Test in Depth

Planning an HTHP test may take three to six months. During this time a well test supervisor liaises with the oil company to ensure that a test program is prepared and approved. The following example is a simplified program to test one HTHP zone from a semisubmersible rig. Even so, it shows that a test requires a plethora of coordinated operations involving most of the people on the rig.

First, having ensured that the well is debris free and the mud is in good condition, run in hole (RIH) with the packer on an electric-wireline setting tool; a casing collar correlation log confirms setting depth.

Hold a safety meeting and clear all nonessential personnel from the work area. Pick up the tubing-conveyed perforating guns. Make up the test assembly (previous page) and pressure test the tool string against the tubing-test flapper valve.

RIH with the test string but do not stab into the production packer with the seal assembly. Pressure test the string, then confirm the packer depth and the space out needed by running a wireline depth correlation log—gamma ray and casing collar correlation tools.

Make up the subsea test tree to the tubing and then the landing string. Rig up the surface test tree and surface lines and RIH landing the fluted hanger at the bottom of the subsea test tree onto the wear bushing at the top of the casing on the seabed (next page). At the same time, the seal assembly enters the packer sealbore. Perform the final pressure test against the tubing-test flapper valve—a bypass ensures that a leak in the flapper valve does not accidentally fire the TCP guns.

Commence testing operations. Close the middle pipe rams and pressure the annulus to 1500 psi, locking open the tubing-test flapper valve

and establishing a reference pressure in the tester valve. Bleed the annulus and surface pressure to zero, open the middle pipe rams and unsting the seal assembly from the packer. Circulate cushion fluid down the tubing—the cushion controls the underbalance during perforation. Reenter the seal assembly, close the middle pipe rams and pressure the annulus to 1500 psi.

Prior to perforating, hold a safety meeting to ensure that everyone understands what is expected during the test. To fire the TCP guns, pressure the tubing to shear the pins in the hydraulic delay firing head. Bleed back the pressure to the required underbalance. The guns will fire after 15 minutes.

Once an increase in wellhead pressure shows that the well has been perforated, open the choke valve and allow the well to flow through an adjustable choke for about 15 minutes, so that the volume below the tester valve is filled with reservoir fluid. Bleed off the annular pressure to close the tester valve for a pressure buildup of about an hour.

Reopen the tester valve for the main flow, which at first passes through the adjustable choke to the burner. After several hours, when the pressure and flow rate are constant, divert flow through a fixed choke and into the test separator. Throughout the main flow, continually monitor hydrogen sulfide/carbon dioxide [H_2S/CO_2] concentrations, base-solids and water volumes, surface pressure and temperature. Closely observe the surface temperature to ensure that the temperature ratings of the BOP and flowline are not exceeded.

After flowing the well, close the tester valve by bleeding off the annular pressure for a shut-in period that is usually one-and-a-half times longer than the main flow. Additional flow and buildup periods may be required depending on the test objectives. Once these have been met, the well must be killed and the test string must be pulled out of hole.

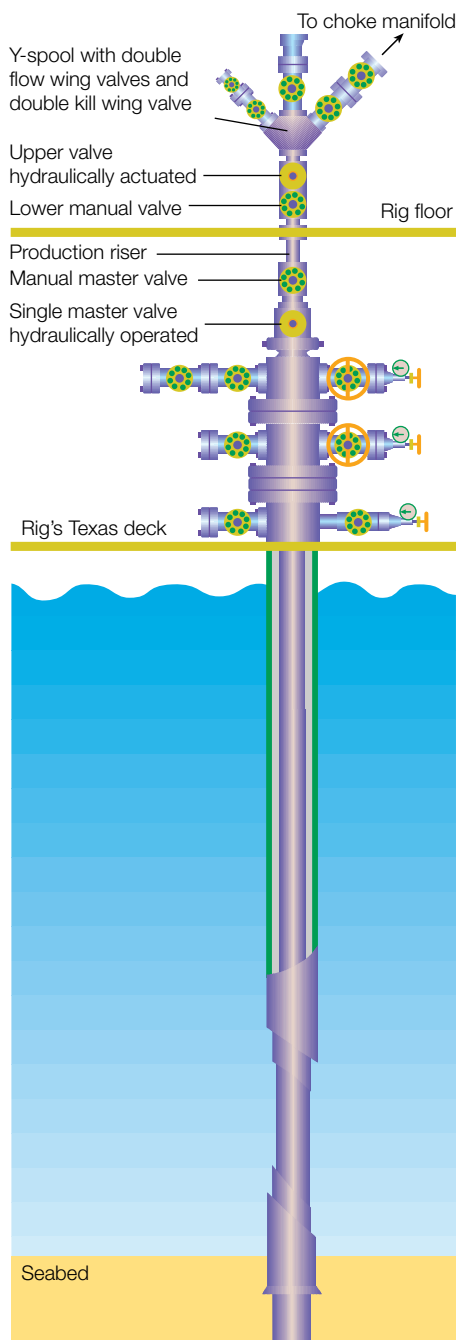
To kill the well, lock open the tester valve using

sufficient annular pressure cycles and bullhead the reservoir fluid and about 10 barrels of kill-weight mud into the formation.

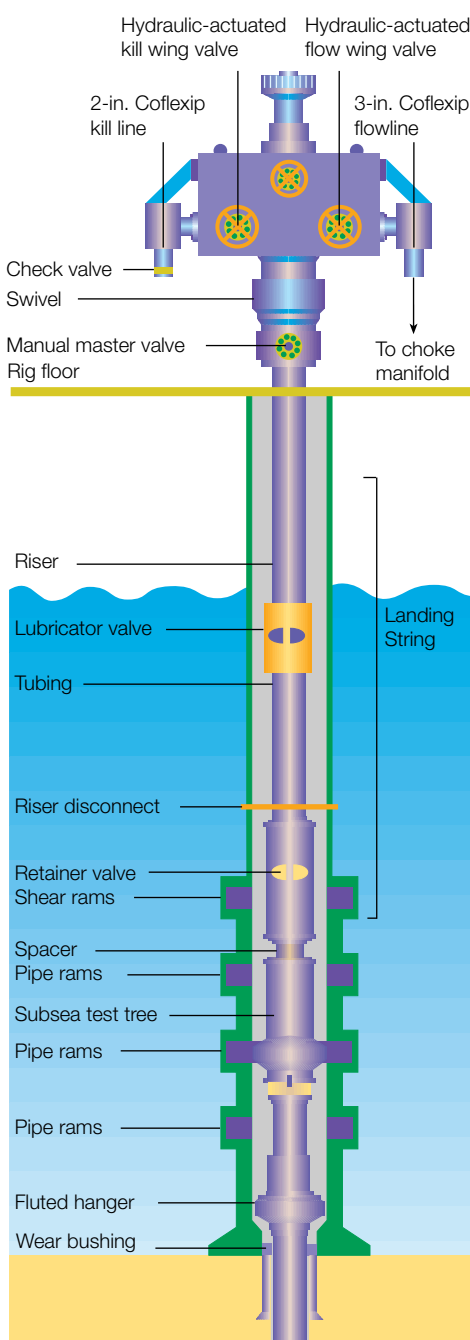
If bullheading creates too much pressure in the tubing, close the tester valve and pressure up inside the tubing so there is a 1000-psi differential between the tubing and the annulus to open the multicycle reverse-circulation valve. Reverse out the fluid inside the test string to the burner using kill-weight mud. Once mud is recovered at surface, start pumping down the tubing directing mud via the rig choke and mud-gas separator to the mud pits. Condition the mud to a constant weight. Stop pumping, close the reversing valve, open the tester valve and bullhead the volume below the reversing valve to the perforations plus 10 barrels into the formation.

Bleed down the test string pressure to zero and for 15 minutes check that the well is not flowing or losing fluid. Open the middle pipe rams, pick up the test string and unsting the seal assembly from the packer. The test string may be further circulated. If the well is stable, rig down surface equipment and pull out of hole.

Jackup



Semisubmersible



□ **Comparing semisubmersible and jackup rig surface and subsea systems.** For jackups, there is no subsea system; all casing is cemented to surface and a straightforward test tree, or wellhead, is used at deck level. Rather than a temporary test head, testing on jackups often utilizes a permanent-type tree. The BOP stack is usually removed for jackup testing. However, it is now possible to retain the BOP stack and run a safety valve below it. The rams seal around the safety valve, which incorporates a nitrogen chamber to assist closure and enable it to cut wireline.

For semisubmersibles, a subsea test tree (SSTT) in the BOP on the seabed allows safe disconnection during testing. Above the tree is a conventional riser-disconnect mechanism and a riser running to the rig's deck. In the SSTT are two subsea control valves below the BOP rams—a flapper valve and a ball valve that operate together. If the rig has to move off station, the valves may be closed using a hydraulic control on surface, and a hydraulic latch above the valve opens to disconnect the string above. The weight of the string left in the hole is borne by a fluted hanger below the control valve. The riser may then be disconnected with the upper part of the test string still inside it.

A retainer valve inside the string is always run in HTHP tests to prevent hydrocarbons in the upper test string from contaminating seawater. The upper test string also contains a lubricator valve—sometimes two for redundancy—to allow wireline assemblies to be used without a lubricator. At deck level is the flowhead or surface test tree. This incorporates the shutoff, kill and choke valves, and allows wireline entry.

investigated in the laboratory and the performance of test tools has been improved to reduce downhole failures. In some cases, the annular fluid is changed to high-density brine, which is solids free but increases the expense of the test.

Subsea Systems: Like drilling, testing is generally simpler on a jackup than on a semisubmersible. On a jackup, the piping to surface is fixed and the control valves are on deck. For a semisubmersible, a subsea

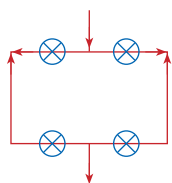
test tree is located in the BOPs on the seabed to allow quick and safe disconnection of the test tubing during testing. Above the tree, there is a conventional riser disconnect mechanism and a riser running to the rig's deck. The choke and kill lines are flexible to compensate for vessel heave (above).

Surface Equipment: At any time during the test it must be possible to shut in the well. Conventionally, this is carried out using the choke manifold valve. In HTHP well tests, a hydraulic actuator is fitted to the flowline valve of the flowhead, or christ-

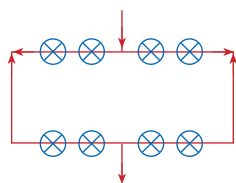
mas tree, and a hydraulic isolation valve is installed between the flowhead and the choke manifold (page 28). Furthermore, a shut-in valve within the subsea safety tree is linked to the ESD panel.

At the heart of the pressure control equipment is the choke manifold. Although separate from the drilling choke, the test manifold has the same purpose, to reduce fluid

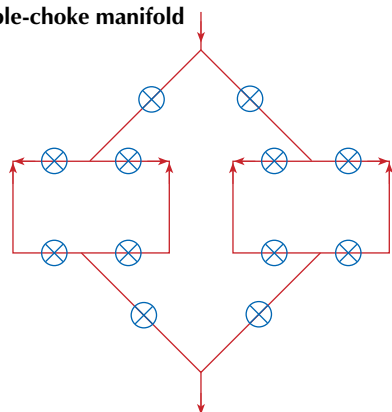
Four-valve choke manifold



Eight-valve, double-block choke manifold



Double-choke manifold



□ **Choke manifold configurations.** To give double isolation when changing a choke during a test, either the eight-valve or double-choke manifold is required.

pressure, usually to less than 1000 psi. The manifold contains adjustable and fixed chokes. To change one of these—either because a different size is required or because of choke erosion—the path through the choke must be isolated by closing valves on either side of it. When a choke is being changed, conventional four-valve manifolds do not offer the double isolation required for HTHP tests. For this reason, eight-valve manifolds that are nearly twice the size of the four-valve version are often used. In other cases, two four-valve manifolds separated by isolation valves are specified (*left*).

Hydrate formation is a serious problem, especially early in the test when the well has not been warmed by extended flow. To avoid plugging the line with hydrate, glycol or methanol may be injected into the fluid before it reaches the choke. Additionally, a heat exchanger warms fluid downstream of the choke. Peculiar to HTHP tests, an extra 15,000-psi choke is sometimes incorporated in the heat exchanger. Therefore, early in the test when hydrates could form in the line—which may be tens of meters long—between the choke and the heater, pressure is initially reduced by the heater choke.

Heating the reservoir fluid also aids separation. For HTHP wells, conventional separation and sampling techniques are sufficient. Fluid volumes are then metered and disposed of, usually by burning at a flare.

Although North Sea HTHP wells present formidable challenges, about 50 have been successfully drilled and many of them tested. And there have been spin-offs. The lessons learned in coming to terms with HTHP wells are now being applied in less extreme conditions.

To date, most of the HTHP wells have predominantly been around 15,000 psi and 320°F [160°C]. But there is a new challenge waiting around the corner: ultra-HTHP wells topping 20,000 psi and 400°F.³⁰ These will be even more taxing and ensure fresh challenges for well planners, drillers and testing engineers. —CF

30. Seymour KP, Stuart C, Simpson B, Lorensen P and Mackay A: "The Drilling of a High-Pressure, High-Temperature Well in the North Sea Using 20,000-psi Well Control Equipment," paper OTC 7337, presented at the 25th Annual Offshore Technology Conference, Houston, Texas, USA, May 3-6, 1993.