Improvements for Kick Detection

For countering gas kicks, long the bane of drillers, a new kick monitoring and diagnosis system appears ready to improve drilling safety.

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Gas kicks pose the greatest threat to safety at the rig site. A kick occurs when wellbore hydrostatic pressure falls below formation pressure, allowing fluids such as gas to enter the wellbore. These dangerous situations are encountered when drilling into formations with higher than anticipated pressures. Failure to swiftly detect the rising gas and 'kill' the kick can lead to disastrous blowouts and, at worst, loss of life (see "What Causes a Kick?" next page).

Until now, drillers have relied on kick detection and kill methods that have changed very little over the years. Kicks are traditionally detected by monitoring the drilling mud balance in the well. During drilling, the flow into the well is measured indirectly by multiplying the number of

A paddle detection flowmeter. This interferes with mud flow and its measurements can be very inaccurate. Now the well's differential mud flow is computed by Anadrlil's highly accurate Accu-Flow sensor, which has no moving parts and does not interfere with mud flow-out (see page 48).

strokes the drilling mud pump makes by the pump's volumetric displacement. This is compared with the mud flow-out, which is usually determined using a paddle flowmeter, and the observed change in total volume in the mud pits (above). When the flow

Troubles with bubbles! How do gas bubbles rise in the well during a kick? Rising bubbles in the experimental flow loop at Schlumberger Cambridge Research, Cambridge, England show that during a simulated kick, the incoming gas rises in a complex way and does not occupy the well's entire cross-sectional area, as traditional kick theories assume.
Flow of drilling mud during tripping. As the drillpipe is pulled out of the well, mud is pumped from the trip tank into the wellbore to replace the volume of steel removed. A second pump keeps the trip tank topped up from the mud pit. The MDS system monitors the pumping rates and the trip tank level and alerts the driller to an overall gain in mud volume as indicated by the trip tank level sensor. This would indicate an influx of fluids into the wellbore. The MDS monitoring system also alerts the driller when the trip tank is in danger of running dry—a situation that leads to a reduction in mud level in the annulus and consequently a drop in wellbore hydrostatic pressure.

out exceeds flow in, gas has entered the well and a kick has started. An influx of fluids into the wellbore may also be indicated by telltale pressure drops and a change in the mud pump's stroke rate.

During tripping, drillers keep a close eye on the trip tank, which is a reservoir for circulating mud (above). If the level indicator shows a sudden increase in the volume of mud in the tank, an influx has occurred.

Once a kick is detected, corrective action must be taken to regain well control (see "How to Kill a Kick," page 47). The well is shut in using the blowout preventers (BOPs) until the pressure stabilizes. A heavier 'kill mud' is pumped into the well increasing the hydrostatic pressure and preventing further influx of gas into the wellbore.

The pumping rate necessary to kill the well is determined from 'kick sheet' calculations made by the driller immediately following shut-in. The sheet has numerous formulas into which various drilling and well parameters are plugged. These are then solved to give the initial circulating pressure at the start of the kill versus the final circulating pressure at the end of the kill (the pressure the driller wants to achieve). The two points are plotted on a pressure/time graph and joined by a straight line (next page, top). From this plot, the number of pump strokes and the pumping rate necessary to control the kick are determined. The objective is to keep the bottomhole pressure (BHP) higher than the formation pressure and so prevent further influx. As the kick proceeds, the driller tries to adjust the well choke to ensure that the circulating pressure follows the straight line plot until the final circulating pressure is attained. Once this is achieved, normal drilling operations can resume (next page, bottom).

This kick killing procedure calls for sound judgment on the part of the driller who has to make decisions under intense stress. If the denser kill mud is pumped into the well too quickly, a rapid pressure increase in the wellbore may damage the formation. But if the kill mud is too light, the kick may worsen.

The main drawbacks of current kick detection methods are their slowness and inaccuracy. Because of this, many minutes may elapse before a kick is detected at the surface; then a great deal of gas may have found its way up the wellbore, a particularly hazardous situation in shallow wells. The driller then has only a few minutes in which to shut in the well and prepare a kill strategy.

Current differential mud flow measurements are particularly prone to error. Mud flow-in calculations depend on pump efficiency—normally assumed to be about 90 percent. But this value can change dramati-

What Causes a Kick?

Wells are controlled by using a drilling fluid with sufficient density to create a wellbore pressure that prevents the influx of formation fluids. This primary control can be lost, resulting in the development of a potentially disastrous kick, for the following reasons:

1) Failure to fill the borehole properly while tripping. As the drillstring is pulled from the hole, the mud level drops because of the volume of pipe removed. This can reduce the hydrostatic pressure in the borehole sufficiently for formation fluids to enter the wellbore. Continuous pumping of mud into the annulus from the trip tank helps avoid this problem (top).

2) Swabbing. The hydrostatic pressure in the wellbore is always reduced when the drillstring or large diameter tools are pulled from the borehole reducing wellbore fluid volume. This can reduce pressure to the level where well control is lost. Swabbing can also produce pressure losses if done too quickly, with high-viscosity muds or gels and with small annular clearance.

3) Lost circulation: Loss of circulation may arise in the following situations:
   - Cavernous or vuggy formations
   - Naturally fractured, pressure-depleted or subnormally pressured zones
   - Fractures induced by excessive pipe running speeds
   - Balling of the bottomhole assembly or sloughing shales in a restricted annulus
   - Excessively high annular friction losses
   - Excessive pressures caused by breaking circulation when mud gel strength is high.

4) Insufficient mud weight. The drilling mud density may fail to provide sufficient hydrostatic head to counteract the formation pressure for the following reasons:
   - Drilling in an abnormal pressure zone
   - Dilution of the drilling fluid
   - Reduction in drilling fluid density because of influx of formation fluids or gas
   - Settling of weighted material
   - Failure to displace riser to kill mud after circulating out a kick.
A typical 'kill sheet' graph. This plot allows the driller to calculate the pumping schedule necessary to kill the kick safely. The initial and final circulating pressures are calculated using simple formulas presented on the kill sheet.

In this example, 1,000 strokes on the drilling mud pump are needed to fill the drillstring. The kill rate is 40 strokes per minute. The initial and final circulating pressures are 1,000 psi (70 kg/cm²) and 500 psi (35 kg/cm²) respectively.

cally depending on factors such as valve seal wear, fluid composition and discharge pressure. Research by Dowell Schlumberger in Saint-Etienne, France, has shown that pump efficiencies fluctuate between 80 percent and 95 percent. These variations alone can introduce a 10 percent error in the flow-in measurement.

Flow-out measurements are prone to even greater inaccuracies. Paddle-type flowmeter measurements vary according to the fluid's density, viscosity and level in the return line. If the flowmeter is uncalibrated, the errors can be as high as 40 percent. Even a calibrated paddle flowmeter is accurate only to 10 to 15 percent.

Accurate differential flow rate measurements and pit gain observations are particularly difficult to obtain on floating drilling rigs because of heaving and rolling of the vessel in response to wind and waves.

Under optimum conditions, traditional differential flow measurements over the entire range of mud flow and type are accurate only to within 25 percent (300 gallons per minute (gal/min) [1,140 liter/min] in 1,200 gal/min [4,540 liter/min])—a typical pumping rate. However, research carried out by Exxon Corporation and confirmed at

A simulated perfect kill. A plot of pit gain and choke operation during a simulated 'perfect kill' using the driller's method. After the initial detection at 10 barrels (bbl) and a short flow check, the kick is circulated out. As gas reaches the surface, the maximum void in the well is created, and the choke needs to be closed down to maintain back pressure.

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Schlumberger Cambridge Research (SCR), Cambridge, England has indicated that differential flow measurements must be accurate to within 25 gal/min [95 liter/min] to ensure early kick detection. As current detection methods are ten times less accurate than this, it is little wonder that drillers worry about kick detection problems.

Other inaccuracies in kick monitoring and control are introduced because of rudimentary assumptions about gas flow within the well. Traditional kick theory assumes that the incoming gas initially occupies the well’s entire cross-sectional area and then rises in the annulus at the same speed as the mud. But laboratory experiments at SCR have shown that this is not the case and that there is a need to improve the modeling of gas flow within the wellbore. The use of oil-rather than water-base muds has added further impetus to efforts to model gas flows more accurately. Because gas dissolves easily in oil-base muds, kick detection becomes more difficult. As a result, greater amounts of gas may enter the wellbore and be transported in solution up the well before reaching a depth at which the hydrostatic pressure falls below bubblepoint. At this level, gas bubbles emerge from solution and displace more mud from the well. This causes the BHP to decrease further allowing more gas to enter the well from the formation. If the kick is left uncontrolled, it can displace all mud from the well, causing a blowout.

A New Approach to Kick Detection and Diagnosis

In an effort to improve kick detection and control, three Schlumberger companies—Anadroll, Sedco Forex and SCR—have been working together on development of computer-controlled wellsite systems aimed at making the driller’s life safer. The kick monitoring functionality of the Sedco Forex Drilling Management (MDS) System provides a complete influx detection package during drilling and tripping. It incorporates the Anadroll Accu-Flow sensor during the drilling phase.

The MDS system can detect the start of a kick three times faster than current methods and can diagnose the gas flow in the well using its in-built prediction methods (algorithms). The MDS system monitors drillpipe and casing pressures to determine, dynamically and more reliably, the downhole pressure, influx density and volume.

In addition, the MDS system carries a data base of drilling information (such as annular volume and drillstring capacity) to automatically answer many of the time-consuming ‘kill sheet’ questions and carry out kill plan calculations. The results are presented on a computer screen in a form identical to the traditional paper sheet, incorporating a drillpipe pressure drop graph.

Faster Kick Detection While Tripping

The MDS system will lead to a significant improvement in kick detection while tripping (above). This composite display shows that, in this well, a 3-barrel influx of formation fluid occurred during tripping out. The mud balance measurements revealed a sudden change in the trend of the mud flow-out with the bottomhole assembly at 5080 feet and 5240 feet, probably caused by mudcake opposite the zone of penetration. Without MDS monitoring this problem would probably not have been detected.

An example of an influx while tripping out of the well. This composite display shows that a 3-barrel influx of formation fluid occurred during tripping out. The MDS hook load monitor and mud balance measurements revealed a sudden change in the trend of the mud flow-out with the bottomhole assembly at 5080 feet and 5240 feet, probably caused by mudcake opposite the zone of penetration. Without MDS monitoring this problem would probably not have been detected.


Mark of Anadroll
Mark of Sedco Forex
the rate of penetration, hook load and mud balance measurements are inputs to a computer that will have a smart alarm system to alert the driller to the influx.

When alerted, the driller would normally stop pulling the drillpipe. This would reduce the suction force and stop the influx. The driller would then check to see if the well was still flowing. If not, the drillpipe would be removed at a slower tripping speed until the swabbed zone was passed.

Faster Kick Detection While Drilling
As mentioned, early kick detection depends on rapid and reliable identification of differential mud flow in and out of the well. With high quality pumps and measuring devices, the mud flow-in, which is fullbore pipe flow, can be determined accurately. But accurate measurement of the mud flow-out is more difficult because the flow is in an open channel, involving complex hydraulics.

To improve the accuracy of mud flow measurements the MDS system will incorporate the Accu-Flow sensor. The Accu-Flow sensor measures oil- or water-base mud flow-outs up to 1,200 gal/min [4,540 liter/min] using ultrasonic sensors and is accurate to within 2 percent, or 24 gal/min [91 liter/min] (below). This high accuracy

![The Accu-Flow sensor on the return pipe. Unlike the paddle flowmeter, the sensor's components do not interfere with the return mud flow. The sensor is easy to install, requiring no special tools.](image)

How to Kill a Kick

There are two commonly used techniques for killing a kick:
- wait and weight
- the driller's method

In practice, drillers often use a combination of the two methods.

![A comparison of kick killing methods. The wait-and-weight method of killing a kick is usually preferred by drillers since it results in lower pressures at the casing shoe.](image)

Wait and Weight
The wait and weight method involves waiting for the well to stabilize and then performing one circulation. A dense 'kill' mud is prepared and pumped from surface to bit following a drillpipe pressure drop schedule. This schedule ensures that once the kill mud enters the annulus, a constant drillpipe pressure is maintained (by adjusting the choke) until the heavy mud returns to surface. This method is popular because it generates the lowest pressure on the formation near the casing seat. The casing shoe is believed to be the weakest point in the wellbore. Thus, if the pressure in the wellbore is allowed to rise, it may fracture the shoe causing lost circulation. In shallow wells this kind of fracturing can lead to disaster. The fractures may propagate to the surface and gas may escape. This can cause fires around land rigs and may fluidize the seabed around offshore rigs, causing them to topple.

For a long openhole section, wait and weight is the method least likely to induce lost circulation. Its main disadvantage is that it requires the longest waiting time prior to mud circulation. During this period, cuttings may settle out and plug the annulus (above).

Driller's method
The driller's method requires two circulations. During the first circulation, the drillpipe pressure is maintained at a constant value until the influx is circulated from the annulus. During the second circulation, kill mud is pumped to the bit while following a drillpipe pressure drop schedule. When the kill mud enters the annulus, the final circulating pressure is maintained constant until the kill mud reaches the surface. This method is preferred if hole conditions permit the driller to start circulating mud immediately. But it does result in high annulus pressure.

makes it possible to detect the start of a kick three times faster than with traditional flow measurements (bottom).

The Accu-Flow sensor is installed on top of the return flow line. Unlike the paddle flowmeters, none of the Accu-Flow components interferes with the mud flow and the device contains no moving parts (right). The return flow line is a pipe which joins the bell nipple to the shale shaker. The pipe is inclined so that the mud flows under gravity to the solids control equipment at sufficient velocity to keep the line clear. Usually, the pipe is partially full and the mud flows as though it were in an open channel. As the flow rate increases, so does the mud level.

The Accu-Flow sensor uses ultrasonic reflections to measure the fluid level in the mud return line. The speed at which a sound wave emitted by the device travels to the mud surface and back is affected by the air temperature. For this reason, three temperature probes are used to measure the temperature gradient above the mud. The sensor’s computer uses this information to calibrate the measurement.

The speed of sound waves is also affected by hydrocarbon gases arising from the mud. The speed of sound in methane, for example, is 30 percent faster than in air, and a 10 percent methane-air mixture will increase the speed of sound by 2 percent. If left uncorrected, this could produce a flow measurement error of about 100 gal/min (380 liter/min) in a 16-inch pipe. A reference target, positioned above the fluid, enables the sensor to accurately measure the speed of sound in the air above the mud, and this tells the computer whether hydrocarbon gases are present in the pipe.

The Accu-Flow sensor calibrates the fluid level in the return line against the flow-in when there is no influx. An inclinometer within the system continuously measures the slope of the return line and enables the computer to correct the flow computations for rig heave. Accuracies of better than 2 percent are achieved regularly when the sensor is properly calibrated (see “Typical Multipoint Calibration Sequence, next page). The system is fully calibrated at startup and again if there are significant changes in the mud. These checks take only a few minutes. During operation, the sensor continuously and automatically recalibrates to account for any changes that might have taken place in the system.

Anadill tested the Accu-Flow Sensor extensively on independent testing appara-

\[\text{Comparison of traditional pit gain and differential flow measurements (delta flow). Using traditional pit gain methods, this 10-barrel kick (the minimum normally detectable) took 8.5 minutes to detect. The Accu-Flow sensor, which monitors the differential flow (flow-out minus flow-in), picked up the kick in only 3 minutes. The 5 minutes saved helped the driller to control the influx more easily and reduced the danger at the wellsite.}\]
Comparison of pit gain and Accu-Flow sensitivities during a kick simulation experiment—measurements versus model results. In this test, the flow-in was kept constant at 380 gal/min (1,440 liter/min). Air was injected downhole for over 8 minutes then stopped. The kick generated a pit gain of 20 bbl (3 m³) in about 20 minutes.

As soon as the kick started, the flow-out increased rapidly. After 5 minutes, the delta flow exceeded 30 gal/min (110 liter/min) which triggered the kick alarm. This alarm continued until the air injection stopped. The bubbles rose up the well and expanded as the hydrostatic pressure decreased. This created a new source of delta flow which increased exponentially with time. Twelve minutes after the start of the injection, the delta flow again exceeded 30 gal/min.

The pit volume measurement showed a continuous increase after the air influx started. On a normal rig, with several pits and agitators, an increase of 10 bbl (1.59 m³) is needed to discern the pit gain—and it would take 18 minutes for this to show up in this well. Only 2 to 3 minutes would be left before the gas bubble reached the surface, leaving little time for the driller to select the correct kick kill method. With accurate flow-out measurements, the influx can be detected at least 9 minutes earlier—giving the driller three to five times longer to decide how to control the well.

### Typical Multipoint Calibration Sequence

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<tr>
<th>Flow-in</th>
<th>Computed Flow-out</th>
<th>Difference</th>
<th>% of 1,200 gal/min</th>
<th>Calibration</th>
</tr>
</thead>
<tbody>
<tr>
<td>382.9</td>
<td>406.7</td>
<td>23.8</td>
<td>2.0</td>
<td>0.941</td>
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<td>504.6</td>
<td>530.4</td>
<td>25.8</td>
<td>2.1</td>
<td>0.951</td>
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<tr>
<td>594.3</td>
<td>621.1</td>
<td>26.8</td>
<td>2.2</td>
<td>0.957</td>
</tr>
<tr>
<td>716.2</td>
<td>730.3</td>
<td>14.1</td>
<td>1.2</td>
<td>0.981</td>
</tr>
</tbody>
</table>

A typical multipoint calibration sequence. The Accu-Flow sensor is installed on a 16-inch pipe with an 8 degree slope, 6 feet from the bell nipple, with water as the circulating fluid in a closed system. The fluid level was measured at several flow rates and converted to a flow estimate using the theoretical level vs flow rate curve. The table indicates that the actual flow-in is 94 percent to 98 percent of the computed flow-out. The nonlinearity is only 4 percent, suggesting a good fit to the actual flow in the return line. Using these observations, a calibration factor (right column) can be computed and applied to the measurements to correct theoretical flow-out.

The Accu-Flow sensor on a test rig at Sugar Land, Texas, USA.
Modeling the Kick

A significant feature of the MDS System will be its ability to interpret the well's dynamic response after closing the BOP. This will provide the means for the system to better determine the density, pressure and volume of the influx. It will also shorten the time required before starting the kill procedure.

The algorithms used in the MDS system were developed in England after several years of kick simulation research by SCR. Following recent concern about gas kick incidents in deep, high-pressure wells drilled with oil-based mud, the UK’s Department of the Environment placed a contract with British Petroleum Corporation (BP) and SCR to develop a large research model (‘R’ model) to simulate kick behavior across the range of conditions found in wells of interest. From this, SCR is completing a simplified engineering model (‘E’ model) capable of being run on a computer workstation in the office for simulation or training.

The ‘R’ model solves the hydrodynamic equations for the conservation of mass and momentum as drilling fluid is pumped down the drillpipe and up the annulus. The model incorporates detailed descriptions of fluid flow and gas/liquid interactions.

The flow of drilling fluid in the wellbore is complicated by the non-Newtonian nature of the drilling mud. Flow in the drillpipe may be turbulent; near the drill collars it varies between turbulent and laminar, in the main part of the annulus it approaches laminar. Algorithms that describe gas/liquid interactions—gas solubility, gas and mud volumetric behavior and dissolved gas dispersion—are included in the model. The model can also account for the two-phase flow produced when gas comes out of solution within the well.

Validation of the model has posed a major challenge because of the paucity of field data on the rate at which free gas rises up the wellbore. For this reason, drillers have made the assumption that gas rises in slug form up the well at the same speed as the mud. However, it is known that the flow and distribution of gas is governed by the speed at which the gas rises relative to the mud. SCR and BP obtained limited information about the dynamics of gas bubbles in drilling muds flowing in a vertical wellbore by participating in a Drilling Engineering Association (DEA) project at Louisiana State University, Baton Rouge, Louisiana, USA. The DEA works together with industry on projects involving drilling problems.

At the university’s dedicated, wellsite testing facility, a controlled amount of gas (an artificial kick) was injected into a 5884-foot [1792-meter] test well and important variables such as pressure, temperature, flow rates and mud properties were continuously measured as the kick was controlled. In addition, a Schlumberger gradianmeter was used to measure the gas fraction in the mud near the hole bottom and within 100 feet [30 meters] of the surface. Comparison of model and experimental results proved very encouraging. However, the experiments made no direct observations of flow regimes or slip velocities and did not simulate the effects of drillpipe rotation. The drillpipe rotation is significant when the kick first enters the well. During the control and kill procedure, the drillpipe does not rotate. Large-scale kick experiments have also been carried out at Anadroll’s 2000-foot [610 meter] Genesis experimental well in Sugar Land, Texas, USA. Nitrogen has been injected at the base of the well and the gas flow characteristics studied.
To shed more light on gas flow problems, SCR carried out a series of experiments using its inclinable 15-meter flow loop (previous page). This loop can be used at any deviation, from horizontal to vertical, and has two separate pumping circuits. The first circuit can pump single-phase liquids such as drilling mud, cement or fracturing fluid. Air can be injected at one end of the 8-inch pipe sections to simulate the development of a gas kick during drilling. The second circuit simulates the flow of any combination of gas, oil and water in producing wells.

At SCR, researchers have also performed detailed studies of bubble flow in a typical mud and have measured gas and liquid velocities directly under different two-phase flow conditions. A good correlation has been achieved between modeled and experimental results (below, left and right).

In order to run the kick model, several other input parameters that describe the well and formation conditions are required:

- Well geometry—drillpipe, casing, surface equipment, riser.
- Physical properties—formation description (temperature, permeability, porosity, pressure) and mud and gas properties.
- Well/model control—control parameters, startup conditions and grid conditions.

Many of these inputs will be stored in a library of standard well descriptive conditions that can be selected by the user. Other information, such as annulus and bottomhole pressures, will also be needed.

Faster methods of kick detection and diagnosis after shut-in will become commercially available with the MDS system in stages throughout 1990-91. After this, the research and engineering departments of SCR and Sedco Forex will focus on developing improved kill planning and monitoring.

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SCR techniques for laboratory flow loop measurements of gas distribution. The average void fraction is determined from a differential pressure measurement since the presence of the gas reduces the hydrostatic pressure between two points. A pair of radio frequency probes detects the bubbles by monitoring the changes in electrical properties in the fluid. This gives a measure of the local void fraction. The bubble velocity is obtained by measuring the time it takes for the bubbles to travel between the probes.

Gas movement in deviated and vertical wells. In a deviated wellbore, gas rises to the top of the pipe. The bubbles coalesce, and the gas moves to the surface faster than in a vertical well.