Permanent monitoring systems measure and record well performance and reservoir behavior from sensors placed downhole during completion.

These measurements give engineers information essential to dynamically manage hydrocarbon assets, allowing them to optimize production techniques, diagnose problems, refine field development and adjust reservoir models.
Reservoir development and management traditionally rely on early data gathered during short periods of logging and testing before wells are placed on production. Additional data may be acquired several months later, either as a planned exercise or when unforeseen problems arise. Such data acquisition requires well intervention and nearly always means loss of production, increased risk, inconvenience and logistical problems, and may also involve the additional expense and time of bringing a rig onto location.

Permanent monitoring systems allow a different approach (above). Sensors are placed downhole with the completion string close to the heart of the reservoir. Modern communications provide direct access to sensor measurements from anywhere in the world. Reservoir and well behavior may now be monitored easily in real time, 24 hours a day, day after day, throughout the lifetime of the reservoir. Engineers can watch performance daily, examine responses to changes in production or secondary recovery processes and also have a record of events to help diagnose problems and monitor remedial actions, rather like monitors in a power plant's control room.

Most systems in operation record bottomhole pressure and temperature, but other measurements, such as downhole flow rate, are being introduced and may become common in the future. However, pressure and temperature provide dozens of beneficial applications.1 This article reviews the development of permanent monitoring, looks at applications with several examples and describes the hardware.


Early Days

Permanent monitoring has its roots in the early 1960s on land wells in the USA. Pressure gauges were needed to monitor the performance of secondary recovery projects, such as waterfloods or artificial lift schemes, where they were required downhole for several weeks. In many cases, the only option available was to run a standard pressure gauge on the end of the completion string (above). The cable for power and data transmission was passed through an insulated connector in the Christmas tree, strapped to the outside of the tubing and then ported back inside the tubing just above the gauge leaving the bore free of any obstructions. Even though the hardware was simple by today’s standards, these early examples proved invaluable to oil companies and showed the diverse use of and benefits from the pressure data gathered.

One example from 1962 is typical of the period. Henderson 6 was the second well completed by the Coronado Company in the Bell Sand of the Old Woman Anticline, Wyoming, USA. A permanent pressure gauge was placed below a conventional pump in a 2400-ft [720-m] well for interference testing and to determine the productivity index. Initial bottomhole pressure (BHP) was 680 psi.

The well produced 340 barrels of oil per day (BOPD) [54 m$^3$/d] with a 60-psi drawdown, but quickly suffered from increasing water cut. Bottomhole pressure returned to 680 psi indicating complete water breakthrough—possibly by water coning. By modifying production and monitoring downhole pressure changes it quickly became apparent that the coning problem would not repair itself and that the well would have to undergo workover. Afterward the well was put back on production and, this time, the pressure gauge measurements were used to control drawdown to just 40 psi to prevent recurrence of water coning.

Other examples from the 1960s show how pressure gauges were used to monitor progress of secondary recovery fronts across fields, to check the operation of subsurface pumps, to provide reservoir data and to calculate individual well drainage during the life of the reservoir.

The Technical Challenge: How Permanent is Permanent?

Although permanent monitoring systems have been around for a number of years, the technology has evolved fairly slowly. Reliability was a major issue with early installations (next page, middle). The first permanent pressure gauge run by Schlumberger was for Elf in Gabon (Africa) in 1972 followed one year later by the first North Sea installation on Shell’s Auk platform. These early systems were essentially adaptations of electric wireline technology. A standard strain pressure gauge was clamped to the tubing and ported to monitor tubing pressure. A stranded single-conductor logging cable was strapped to the outside of the tubing exiting at the wellhead. Data were recorded on a standard acquisition unit.

Many early failures were caused by damage during installation or by cable problems at a later date—either by loss of electrical continuity or breakdown of insulation causing a short circuit (next page, top). Statoil report that many cable failures occurred at splices and now request splice-free cables. Detailed analysis, such as that performed by Petrobras on systems run in Brazil and the North Sea, shows how reliability has improved. More recently a detailed research and development project by Schlumberger, 40% funded by the European Community THERMIE project, has resulted in development of a new generation permanent gauge and its associated components for even greater reliability.

Present systems are engineered specifically for the permanent monitoring market and have a life expectancy of several years (see “Hardware,” page 37). Gauges have digital electronics designed for extended exposure to high temperature and undergo extensive design qualification life tests and strict quality checks during manufacture before being hermetically sealed. They are not designed for maintenance.

Cables for permanent installations are encased in stainless steel or nickel alloy pressure-tight tubing that is polymer-encapsulated for added protection. All connections are verified by pressure testing during installation.

Connections through tubing hanger and wellhead vary depending on the type of completion—subsea, platform or land—but components are standard, tried and tested designs made in conjunction with the tubing hanger and wellhead manufacturers.

Data transmission and recording are tailored to oil company needs, and wherever
Permanent monitoring system reliability in the North Sea. Data on Schlumberger permanent monitoring systems installed in the North Sea in the last nine years shows improving reliability. Most working systems are less than three years old (top), but a significant number have been working longer. Most failures occurred during the first year and were likely caused by cable or connection damage during installation (middle). Ideally, systems should remain working during the life of the well so that average system life divided by average well life equals 100%. System life reached only 54% of well life for installations in 1988 (bottom). This figure has steadily improved and, not surprisingly, is 100% for systems installed this year.

Permanent downhole cable evolution. Standard monoconductor logging cables were used with the first installations (1). Later, cable bumpers and polymer encapsulation improved protection (2). In the North Sea there was a shift to tubing-encased cables in the mid-80s. The first type used Teflon insulation which allowed the cable to slip inside the tubing, breaking connections (3). Teflon was replaced by a friction material to alleviate this problem (4). This type of cable is now standard in the North Sea. Petrobras uses a combination of tubing-encapsulated cables and bumpers (5).

3. An interference test measures the pressure response in one well to changes in production or injection in a second well. The objective of the test is to assess communication between the wells. Productivity index is a measure of producibility of the reservoir and is equal to flow rate divided by pressure drawdown.

Productivity index is a measure of producibility of the reservoir and is equal to flow rate divided by pressure drawdown.

6. European Community THERMIE project on Improving the Reliability of Permanent Down Hole Pressure Gauges.


The life expectancy of a permanent monitoring system depends on many factors, the most important being bottomhole temperature. High temperature increases electronic aging and failure rates. However, there are functioning gauges that have been in wells for more than 10 years and these are obviously not the latest technology.

possible industry standards are used so that signals may be integrated with other systems. For example, many subsea completions have memory modules called data-loggers that record, for instance, wellhead pressure or the status of control valves. Permanent gauge data may be fed to interface cards located in the data-logger so that data transfer may be executed in one step.

Of equal importance are planning and project management for each installation. Although most permanent monitoring hardware may be considered off-the-shelf, several parts may have to be customized for special types of wellhead. Longer lead times may be needed if the project requires custom-built equipment. For example, in subsea well completions, the permanent gauges are connected to subsea-mounted electronic pods with acoustic data links to surface.

Specialist teams of engineers and technicians install permanent monitoring systems and work closely with rig crews who are fully aware of the importance of installing a working system. Pressure gauges are usually connected to the cable at the workshop where pressure or welded seals can easily be made and pressure tested. At the wellsite, the gauge is mounted onto a mandrel, which is connected to the tubing. The cable is supplied on a reel and is run in the hole with the tubing. Great care must be taken to avoid damaging the cable at this stage. Cable protectors placed on every tubing joint help prevent damage as the system is run in the well. Checks on both pressure integrity and gauge operation during the entire procedure ensure a working system.

For certain subsea installations, hookup to surface acquisition equipment may involve divers and diver-matable connections or remotely operated vehicles (ROVs) and connections to acoustic data-loggers or telecommunication equipment.

Once they are connected and running, permanent monitoring systems begin payback in many different ways as the following case studies show.

A Decade's Experience in the North Sea Elf Enterprise Caledonia Limited (EEC) has used permanent monitoring systems in its well completions since 1983. The first application was on Scapa, a small satellite field 5 km [3 miles] from the Claymore platform in the UK sector of the North Sea (above). The Scapa well C-47 was drilled at a high angle—67° to 68° deviation—from the Claymore platform.

A one-year extended well test (EWT) conducted by EEC helped determine the long-term deliverability of Scapa. Because of the difficulties in running wireline operations in such a high-deviation well and with the Claymore platform rig working on other wells, it was not possible to enter C-47 during this period. The only way to obtain downhole pressure data to evaluate the EWT was by using permanent monitoring systems. The outcome of the EWT paved the way for the development of the field with a multiwell slot subsea template.

The second application was in the same field, but this time in a newly discovered, lower sand body in subsea well S-20. Pressure data from the permanent monitoring gauges installed in this well contributed to the estimated reserves being increased from approximately 40 million barrels to 60 to 70 million barrels. More recently the estimate has been increased again to 100 million barrels. Four more wells were drilled and completed with permanent gauges.

Permanent pressure data have been used to model the interaction between the three oil accumulations of the Scapa field—directly through extensive interference testing and indirectly through use of the data in material balance and simulation studies. This has resulted in a more thorough understanding of field behavior, leading to optimized recovery of reserves and continued development drilling.

Scapa has also seen the use of some novel hardware applications. A conventional wellhead uses a dual-bore Christmas tree, which has to be oriented to allow the use of the traditional wet connect system (see “Hardware,” next page). However, EEC’s concentric completion system does not need to be oriented. To realize the full benefits of this tree, EEC has successfully used an inductive coupling system at the interface between the tubing hanger and the Christmas tree. Also, because the umbilical connecting Scapa electrically to the Claymore platform has reached its capacity, data from all the wells are stored in subsea data-loggers. These are periodically interrogated acoustically during one of the many trips by supply boats to the area. Recently, the same method has been applied to collect data from flowmeters mounted on a subsea water injection line.

Saltire field was the next application, coming on stream in 1993 on the back of the Piper redevelopment. Wells were drilled from a minimum facility platform that would
Pressure Gauges

Pressure gauges are built to more exacting lifetime specifications than wireline- or drillstem test-conveyed systems. A temporary completion may contain gauges that stay downhole for several months during a long-duration well test. However, permanent gauges have to stay in wells for several years. Reliability is a key feature and this is inversely proportional to temperature, time and wellbore chemistry. Gauge electronics are designed with this in mind.

Schlumberger permanent gauges use a modified version of UNIGAGE electronics. These electronics are used in Schlumberger memory gauge recorders and are designed for rugged, long-duration operations. Modifications include opting for totally soldered and hermetically sealed, solid-state electronic components that may be bigger or more expensive, but are temperature-stable for long periods. Any drift in the electronics is automatically corrected. Once installed, the gauges are not going to be used on other wells, so there is no need to consider maintenance. To this end, all internal connectors and sockets are eliminated and, after 100% burn-in and calibration testing, the gauge housings are welded shut during manufacture. Connections to the outside are provided by a feed-through connector (right).

Sensors used in permanent gauges have slightly different specifications than pressure gauges used in well testing. The emphasis is on long-term gauge stability rather than fast dynamic response. Quartz crystals are most often used although other types of sensor, such as sapphire sensors, may also be used.
Gauge Mandrel

Gauges are housed in the protective recess of a gauge mandrel (above). This provides complete gauge protection against mechanical damage along the entire gauge length. Gauge protection is especially important in deviated wells, where the gauge has to pass through liner hangers, or during completions from floating vessels.

Bottomhole Connectors

There are two connections to the permanent gauge: electrical connection to the cable for power and data transfer, and hydraulic to connect the sensor to tubing pressure. Electrical connection is usually made at the workshop. The conductor is soldered to the feed-through connector. The pressure connection is made at the wellsite with metal-to-metal seals.

Metal-to-metal seals are also made between the gauge and its gauge carrier or gauge mandrel. At the wellhead end of the cable, metal-to-metal seals are again made to ensure that connections are pressure tight. Each connection is pressure tested and verified during installation at the wellsite.

Cable

Cables form a major part of the budget for a permanent monitoring system—up to 30% of the cost. Permanent downhole cables have to withstand pressure, temperature and exposure to highly corrosive wellbore fluids during the life of the permanent installation. They also have to be mechanically rugged so that they are not damaged during installation. Cables consist of copper conductors surrounded by Teflon insulation material, antislip filler, standard 1/4-in. stainless-steel or nickel alloy tube and thermoplastic encapsulation material (page 35, top). The filler material supports the cable inside the tube preventing the entire weight of the cable from being supported by the top connector. It also allows
some movement inside the stainless-steel tube so that the cable is not exposed to thermal stresses. The metal tube has up to 20,000-psi collapse pressure and prevents wellbore fluid contamination which could short circuit the insulation. Encapsulation helps prevent cable damage such as nicks and crimping during installation. Even so, the cable requires careful handling.

Cables usually have single conductors, but can be manufactured with more. Encapsulation materials and sizes can also be tailored to oil company requirements.

**Cable Protectors**
Cables are clamped to the tubing string using cable protectors. These are clamped across tubing joints—the place where the cable flexes slightly over the collar (above right).

**Tophole Connectors**
Connections are made by pressure-tight, compression-fit, metal-to-metal seals between the downhole cable and the tubing hanger and downhole cable and gauge. Other elements of the completion may also require connections, for example, if the cable has to pass through a packer.

**Wellhead Connectors**
There are many types of wellheads and the cable from a downhole permanent gauge must pass through to an exterior terminal. Connections are first made to the tubing hanger. Connections to the other side of the hanger depend on the type of wellhead. If the wellhead is at surface—for example, a wellhead on a land well or a wellhead exposed above the sea on a platform—then a connection has to be made through the wellhead to a terminal block (previous page, bottom). The signal is then routed to the surface acquisition system.

For subsea wellheads, the connection is more complicated (right). An electric wet-connect (EWC) system is commonly used enabling a direct link across the wellhead. The EWC consists of a male pin situated in the tubing hanger. The female socket sits below the valve block and is oriented to align with the male pin. On the outside of the wellhead valve block is a flanged outlet to either a diver-matable subsea electrical connection or a remote-operated vehicle connection. The signal is then routed to an acoustic transducer, an integrated control pod or a subsea umbilical.

**Subsea wellhead connectors. Signals have to pass through the tubing hanger and Christmas tree to emerge at a suitable connection—diver or ROV mate-able. A male electrical wet-connect makes the connection through the tubing hanger to the permanent downhole cable. The wellhead valve block is prepared with a flanged outlet and female wet-connect. Contact is made when the oriented wellhead is lowered onto the tubing hanger.**

**Acquisition Systems**
There are a number of different methods for collecting data. Often on subsea completions, it is possible to hook into existing data-gathering systems. These have been set up to monitor subsea wellheads providing such data as surface flow rates, temperature and pressure as well as valve positions and status. Permanent gauge interface cards are now available for most data gatherers, which are normally connected to platforms by seabed umbilical cables.

A system that does not use an umbilical cable is a hydro-acoustic system (next page). In this approach, the permanent gauge signal is collected at a data acquisition unit (DAU) that logs and performs a quality check of each measurement. The DAU can be periodically interrogated

using an acoustic transducer that may be hung over the side of a boat, rig, platform or even from a helicopter. The subsea equipment is powered by a battery pack that can be replaced by divers or a ROV without losing the DAU memory.

For platforms, several permanent gauges may be connected to an autonomous surface unit that is rack-mounted in the cabin or packaged in an explosion-proof box near the wellhead. This acquires and records the raw measurements and communicates with the oil company’s computers via standard modem data links or local area networks. Communication may be via satellite to the oil company office anywhere in the world.

Software
Permanent gauge monitoring software enables a user to control and monitor permanent gauges from anywhere in the world. This Windows-based PC software makes full use of standard communications networks and straightforward point and click menus and icons. With this software, a user can view the real-time downhole gauge measurements directly or display recorded data files. In addition, the data can be shared via networks with other users for further analysis and interpretation.

Power Supply
Gauge power is provided from surface directly from subsea umbilicals, platform supplies or from subsea battery packs. On land in sunny areas, batteries may be recharged using solar panels.
not allow concurrent well intervention during a drilling program lasting several years. When drilling stopped, the platform would become unmanned. Any well reentry for data gathering would then be extremely costly. So EEC decided to incorporate permanent monitoring systems in the completions from the first stages of field development.

The reservoir proved to be complex and permanent pressure data served to optimize production (below). For example, the bubblepoint of the crude oil in one of the reservoir members is 3700 psi and the initial formation pressure, 4600 psi. So drawdown had to be less than 900 psi to sustain gas-free production. High skin factor in the first well meant that as large a drawdown as possible would be needed for adequate production—introducing a further complication. However, the pressure could be carefully monitored and production optimized to maintain reservoir pressure at around 40 psi above bubblepoint.

Additional benefits of continuous pressure recording have included cross-field interference testing that has shown that although the reservoir is mapped as being compartmentalized, there is generally pressure communication between compartments. For example, pressure changes of less than 5 psi are detected in a well approximately 600 m (2000 ft) away from one being pulsed (right). These data helped optimize well locations and water injection strategy to maintain reservoir pressure, and have also provided a useful history-matching parameter for the reservoir simulator model.

Interference test. Pressure pulses recorded in Saltire A01 (top) are seen as small changes in pressure recorded by the permanent gauge in Saltire A04 (bottom). (Courtesy of Elf Enterprise Caledonia Ltd.)

Permanent pressure data used to optimize production. Production from one of the Saltire reservoir members was adjusted several times until an acceptable bottom-hole flowing pressure was achieved in Well A07. Abrupt changes in pressure may be seen each time the production was adjusted. (Courtesy of Elf Enterprise Caledonia Ltd.)
A more unusual use of permanent pressure data confirms the successful isolation of an underlying higher pressure interval that would otherwise have been difficult to demonstrate (below).

The final EEC field application is on a single subsea well development—the Chanter field. This has separate reservoirs of oil and condensate. Initially the well produced oil and was later converted to produce condensate. Continuous pressure monitoring kept reservoir pressure from dropping below oil bubblepoint during that particular phase of production and also helped optimize the timing of conversion to a condensate producer.

The pressure data also provided input to calculate the accumulation in contact with the well and evaluate the effectiveness of the aquifer as a reservoir drive mechanism. This information will help establish the requirement for a possible additional well in the field. In subsea wells such as Chanter, the cost of the permanent monitoring system is immediately recouped if only one well reentry operation is avoided.

Apart from the major applications described above, EEC has also found permanent monitoring data useful in other circumstances. Knowing bottomhole pressure allows calculating the correct weight of kill fluid. This minimizes formation damage while ensuring an effective kill. Knowledge of bottomhole pressure also allows optimal control of underbalanced perforating.

Based on their experience in the North Sea, EEC considers permanent monitoring systems beneficial whenever development involves satellite fields, subsea completions, difficult access well completions or limited access platforms.

**Norwegian Connection**

Two fields in the Norwegian sector of the North Sea highlight several more applications of pressure data recorded by permanent monitoring systems.11 Gullfaks and Veslefrikk fields operated by Statoil are complex and require careful reservoir management. Gullfaks is in the central part of the East Shetland basin, 175 km [109 miles] northwest of Bergen, Norway. Veslefrikk is about 30 km [19 miles] south of Gullfaks (next page, top).

Gullfaks is heavily faulted with a number of sealing or partially sealing faults. One important reservoir monitoring objective is to measure the degree of communication between the fault blocks. Veslefrikk started production with commingled wells. Here gauges are used in dedicated wells to monitor the two reservoirs independently. Data are used in both fields to ensure single-phase oil flow in each fault block, to monitor and optimize well performance with time, for transient well test analysis and for matching numerical models.

At present, Statoil has more than 50 permanent gauge installations. Each is connected to a communications system that allows gauge control from PCs located anywhere in the world. For example, a well test can be monitored remotely and the data sampling rate adjusted during the test.

**Gullfaks**—Gullfaks field development is based on single-phase oil flow without free-gas in the reservoir. In wells with permanent monitoring systems, bottomhole flowing pressure (BHFP) is maintained slightly above saturation pressure by adjusting the flow rate (next page, bottom).12 This results in a potential increase in the individual well production rate of 100 m³/d to 500 m³/d [630 B/D to 3150 B/D]. In wells without permanent monitoring, calibrated curves based on empirical multiphase equations and permanent pressure data from nearby wells are used.
Data from permanent gauges are used to history match numerical models for each production area, to identify the degree of communication between wells and to control the flow into and out of each block to maintain material balance. For example, geological interpretation indicated a fault between two wells—a producer and an injector. The producer was shut in during start of injection. Permanent gauge data from the producer showed an increase in pressure during this start-up period indicating excellent communication across the fault. Combining openhole pressure data and permanent pressure data has revealed such interwell communication in a number of wells.

About 40% of Gullfaks producers are gravel packed and contribute more than 50% of production.\textsuperscript{13} In the majority of these wells, permanent gauges continuously monitor downhole flowing pressure and temperature. These data provide input to monitor gravel-pack performance and may be used to analyze and identify problems caused by a variety of phenomena, including migration of fines and scales.

As an alternative to gravel packing for sand control, Statoil has used indirect vertical fracturing to complete several wells.\textsuperscript{14} This method allows production from unconsolidated sands through less productive, fractured, consolidated intervals. Availability of real-time downhole pressure data allows fracturing operations to be optimized and, for operational reasons, these data can be obtained only from permanently installed monitoring systems.
Even though permanent sensors were deployed several tens of meters above perforations, transient analysis of their pressure data gave satisfactory results when compared to data from wireline pressure gauges located much closer to producing zones. In this example, the wellbore storage effect did not dominate transient analysis, which allowed a comparison of results. Differences in calculated values of skin were attributed to frictional losses along the tubing to the permanent gauge. This allowed corrections to be made to other permanent gauge data sets in the area to estimate true formation skin (right).

Gullfaks produces from a mixture of weak formations and exhibits large variations in depletion in the various fault blocks and reservoirs. In many cases, only a small margin exists between formation fracture pressure and pore pressure. Safe drilling depends on obtaining an estimate of pore pressure for each zone before penetrating the reservoir. Permanent pressure data are used to calculate pore pressure and hence determine the optimum mud weight for well control without fracturing the formation.

Veslefrikk—The 12,000-m³/d [75,000-B/D] Veslefrikk field, located 145 km [90 miles] northwest of Bergen, was considered a marginal field. To reduce total investment, commingled production and injection was planned from the Brent and Intra Dunlin Sand (IDS) reservoirs. Control is obtained by selective perforation in producers and downhole chokes in injectors. A carefully planned data acquisition program during the initial production phase provided information about reservoir properties, production potential and well behavior. In addition, two of the largest uncertainties were partially resolved: the degree of communication across the main arcuate fault and the vertical transmissibility between the Lower and Middle Brent through the low-quality Rannoch sand.

This information led to improved reservoir description and allowed adjustments to be
## Reservoir Management Applications

<table>
<thead>
<tr>
<th>Application</th>
<th>Description</th>
<th>Benefits</th>
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<tbody>
<tr>
<td>Interference testing</td>
<td>Establishes the degree of communication across the field, between wells, between fault blocks and also the vertical transmissibility between reservoirs.</td>
<td>• Wireline intervention eliminated. • Limited planning involved. • Observation of effects caused by any change in production or injection in wells where permanent gauges are installed.</td>
</tr>
<tr>
<td>Reservoir pressure control</td>
<td>Maintains bottomhole flowing pressure above a threshold by monitoring permanent gauge data while adjusting water or gas injection, or while varying production.</td>
<td>• Individual well production maximized. • Injection rates optimized. • Sand production eliminated by controlling drawdown. • Completion costs optimized.</td>
</tr>
<tr>
<td>Transient well testing</td>
<td>Performs a pressure buildup test automatically whenever a well containing a permanent gauge is either deliberately or inadvertently shut-in. Similarly a pressure drawdown test is performed when the well is opened up.</td>
<td>• Transient analysis of problem wells with minimum intervention. • Real-time, early reservoir data with no cable in the tubing during an extended well test or during early production. • Remote control and analysis of data. • Limited production loss by eliminating wireline operations.</td>
</tr>
<tr>
<td>History matching</td>
<td>Provides continuous recording of pressure data during the lifetime of the well.</td>
<td>• Verification or adjustment of reservoir models. • Improved reservoir description. • Improved estimation of reserves.</td>
</tr>
<tr>
<td>Well performance</td>
<td>Provides continuous recording of pressure data.</td>
<td>• Completion performance established. • Gravel-pack performance established. • Monitoring of migration of fines or scale buildup. • Wellbore hydraulic curves calibrated for optimizing gas lift.</td>
</tr>
<tr>
<td>Hydraulic fracturing</td>
<td>Monitors downhole pressure during hydraulic fracturing.</td>
<td>• Fracture length optimized. • Real-time surface readout of downhole pressure data during a frac.</td>
</tr>
<tr>
<td>Bottomhole pressure data</td>
<td>Provides continuous knowledge of bottomhole pressure.</td>
<td>• Pore pressure calculated for safety while drilling development wells. • Computation of accurate kill fluid weight. • Calculation of accurate under-balance or over-balance before perforating.</td>
</tr>
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## Field or Well Condition Applications

<table>
<thead>
<tr>
<th>Application</th>
<th>Description</th>
<th>Benefits</th>
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</thead>
<tbody>
<tr>
<td>Restricted access</td>
<td>Installs permanent monitoring systems whenever access is restricted by subsea completion wells, small platforms or single wells, remote land wells or when other activities on a platform, such as continuous drilling, prevent well access.</td>
<td>• Elimination of costs associated with wireline intervention. • Operational hazards reduced. • No personnel required. • No rig required. • Only method to record data in many cases.</td>
</tr>
<tr>
<td>Highly deviated wells</td>
<td>Installs permanent monitoring system with completion.</td>
<td>• Elimination of costs of coiled tubing or snubbing equipment to convey wireline pressure gauges.</td>
</tr>
<tr>
<td>Pumping wells</td>
<td>Runs gauges to monitor pump inlet pressure and pump outlet pressure.</td>
<td>• Pump efficiency established. • Pump rate optimized. • Pump maintenance planned. • Only practical method to record downhole pressure data.</td>
</tr>
</tbody>
</table>
Multisensor Applications

All the applications described above require only one permanent downhole pressure gauge—even though in some cases a second gauge has been used for redundancy. There are many other applications for permanent monitoring systems and some require more than one sensor (previous page).

Many oil companies have wells equipped with electrical submersible pumps that are impractical to log by wireline methods. A single permanent pressure gauge may provide useful information about well or reservoir performance, recording formation pressure when pumps are switched off. However, monitoring pressure during pumping—at the pump inlet and outlet—provides additional information about pump efficiency. Pump efficiency has an impact not only on production, but also on pump life and workover schedules. Tracking pump performance and adjusting pump speed to match reservoir conditions increase efficiency and pump life.

A relatively new technique uses permanent pressure gauges and a venturi to monitor downhole flow rates. A venturi is essentially a restriction placed in a flowline—in this case the tubing. The venturi causes a small change in pressure—typically less than 10 psi—which is related to the fluid velocity. Often three pressure gauges are used, two for the venturi—to measure differential pressure—and the third one for standard pressure measurements some distance away from the other two, so that fluid density may also be calculated.

A Permanent Seat in Completion Plans?

Driven by the trend toward unmanned platforms, subsea completions, limited access wells—either because of their remote location on land, top-side activity offshore or well deviation in general—permanent monitoring systems are becoming an established part of well completions. Now that reliability issues have been resolved by sound project management and the introduction of new technology, permanent monitoring systems are a proven cost-effective and safer alternative to intrusive data acquisition methods.

Applications for pressure data gathered by permanent monitoring systems are numerous, ranging from reservoir evaluation during extended well tests or early in the production cycle, to lifetime reservoir and well management. Modern communication systems enable remote control of the sensors and make the data accessible from offices anywhere in the world, increasing the value of permanent monitoring systems. —AM

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