Permanent Monitoring: Taking It to the Reservoir

Instruments able to continuously report current downhole conditions in producing wells have become powerful tools for managing oil and gas reservoirs. Recent refinements in deployment, fiber optics and interpretation methods have combined to greatly expand the role of permanent monitoring sensors and the types of wells and fields in which they may be applied.
In the 1990s many engineers in the oil and gas industry resisted the use of downhole sensors and controls. Their reliability had not yet been proven over the 20-year or more life span typical of many producing wells. This insistence on long time periods between failures is reasonable: The typical well targeted by operators for permanent monitoring systems tends to be complex or in remote areas, such as deep water. Both these factors greatly increase the cost to retrieve, repair and reinstall failed parts.

In response to industry concerns, sensor suppliers leveraged techniques from other industries to qualify product reliability and to forecast sensor life expectancy. Studies used survival analysis techniques that look back using case histories to measure equipment reliability and that look forward using reliability modeling. They also analyzed in detail the failure modes for each system’s key components and deployment.

Applications of lessons learned from these and other studies have led to improvements in long-term reliability of intelligent completions—a primary application for permanent monitoring systems. As a consequence, reliability is rarely questioned today during discussions about permanent downhole sensors.

Traditionally, these sensors have been used to gather data at single points along the wellbore—usually above the packer. A sudden change in downhole temperature or pressure, for example, might indicate water or gas breakthrough or a breach of zonal isolation. While this approach often is sufficient for operator needs, recent innovations in permanent sensors, particularly digital sensors and fiber-optic distributed temperature sensors (DTS), allow engineers to take many more temperature and pressure measurements along the length of the wellbore.

Hardware solutions aside, the value realized from monitoring systems is very much a function of how data are analyzed. Some operators who today routinely include permanent pressure and temperature sensors in all completions of a certain type may fail to fully assess the data delivered by their sensors and do not realize the full benefit of the information gathered. They may not analyze it at all and only store it, as they might offset-well data, to be referenced only when planning future drilling programs or when attempting to understand the cause of sudden production problems.

A more proactive approach integrates production data from various sources—including permanent downhole sensors—using software programs to manage the continuous data stream in real time. Schlumberger has developed THERMA thermal modeling and analysis software for wells with distributed temperature sensors. The software uses a steady-state pressure model combined with a thermal solution to model most black-oil and composite-fluid scenarios and thereby facilitate analysis of DTS data.

Used this way, continuous real-time pressure and temperature readings can have an impact akin to that of obtaining production logs while the well is producing. This is particularly attractive in wells where traditional interventions are problematic or the cost of deferred production is unacceptably high.

This article discusses ongoing efforts to bring permanent downhole sensor measurements to the reservoir. It also describes the application of software as well as the expert interpretation that clarifies the data to maximize value.

A case history from Azerbaijan illustrates the value of using fiber-optic technology to track downhole production changes. Another from offshore India demonstrates the effectiveness of a new technology aimed at overcoming the problem of establishing communication and control between upper and lower completions. The same study examines how information garnered while monitoring the sandface allows operators to better understand subtle but crucial reservoir characteristics. And a redevelopment effort offshore Malaysia showcases how a hybrid opto-electric system, when combined with other standard oilfield tools, may be used to optimize development of unexploited reservoirs.

**Measuring Top to Bottom**

Particularly when reservoir layers are few or well-defined, pressure and temperature point sampling is a powerful reservoir analysis tool and accounts for a majority of permanent sensor applications.

However, pressure and temperature measurements taken at discrete points are cumulative in nature. That is because the characteristics of the fluids at the sensor locations are the result of the varied environments through which they have passed. As a consequence, a significant change at some location along the wellbore between sensors may be masked, distorted or missed entirely at the sample point.

Recent developments within the oil and gas industry have done much to address the shortcomings of point sampling. Key to this effort has been industry acceptance of fiber optics. Suitably robust to withstand the rigors of installation and to survive for extended periods in rugged downhole environments, fibers installed in cables or inside control lines allow temperature measurements to be taken along the entire length of the wellbore. During the past decade, numerous innovations in fiber-optic sensor technology have added to the industry’s ability to communicate between the surface and the sandface. As a consequence, over time the focus of permanent sensors has been changed from monitoring the well to characterizing the reservoir (above).
This is an important distinction. By using a fiber-optic distributed temperature system that takes measurements at the point of fluid inflow rather than at some distance away, it is possible to interpret temperature to provide a depth- and time-based profile. This interpretation can then be analyzed and the well’s flow profile obtained.

Until recently it has not always been possible to install the sensors at the sandface. For example, many offshore wells are complex completions that include gravel packs and must be installed in two stages. The lower stage containing the gravel-pack assembly is placed across the production zone, followed by the upper stage containing the packer and production tubing (below).

Connecting cables and hydraulic lines between the upper and lower completions as part of the second step in the procedure is extremely problematic. As a consequence, operators have traditionally opted not to deploy gauges over the reservoir interval of the lower completion.

Two key innovations have helped address this basic connectivity issue. The first is a DTS system in the form of a fiber-optic dual-stage mateable system. It may be installed in either a cable or a control line pumped into wells through the tree once both upper and lower completions are in place. DTS systems are able to take a temperature measurement every meter along the well from surface to total depth. The second innovation is a wireless communication system that transfers power and data using an inductive coupler at the interface between the upper and lower completions. By so doing, it makes possible the deployment of digital temperature and pressure sensors along the lower completions.

Right Tool, Right Job, Right Way

It is now possible to install an optical DTS system in a two-stage completion. First, a hydraulic conduit is strapped to the lower production string. A similar conduit attached to the upper completion is then connected to the lower section by means of a special control-line wet-mate system able to orient and align the two lines. Once the completion is installed, an optical fiber is carried by fluid circulated through the conduit and placed along the entire length of the completion.

DTS systems can also be embedded in the gravel-pack shrouds on the outside of the gravel-pack screens (next page, top right). This configuration is important because the wellbore outside the basepipe behaves like the reservoir rock. Therefore, the temperature measured by the DTS at the producing interval is the inflow Joule-Thomson temperature and is not influenced by the temperature of the fluid mixture flowing up the wellbore—the axial fluid flow. This means that the flow from an individual reservoir layer can be readily distinguished from the axial fluid. Additionally, owing to the DTS positioning, the inflow temperature is a direct function of the drawdown pressure and the Joule-Thomson coefficient, which is dependent on fluid properties.

The resulting temperature profiles can be converted into flow profiles using a thermal model of the well and the near-wellbore region built specifically for use with DTS systems (next page, bottom right). Near-wellbore flow is a function of the reservoir and flowing wellbore pressures, zone permeability, reservoir size and fluid properties. Flow to the surface is a function of the completion, inlet and outlet pressures, gravity effects and fluid properties. Therefore, pressures can be solved throughout the system for flow rate, reservoir pressure or surface flowing pressure through a nodal finite-element pressure analysis.

Two-stage completion. A two-stage completion involves placing the lower section of the completion across the zone of interest. The lower section is isolated from the upper portion of the well by a packer with a polished bore receptacle (PBR) facing upward. If sand control is required, a workstring with a polished bore stings into the packer and circulates the sand into place at the screen. The workstring is removed before the second stage of the completion to install the upper section of the well. This second-stage operation includes installation of production tubing whose lowest joint is a polished bore. This is stung into the polished bore receptacle of the packer to tie the well back to the surface.
Once pressures throughout the system have been determined, a radial near-wellbore thermal model is used to calculate the temperatures from the far geothermal temperature in each reservoir zone as a function of the fluid, formation and completion thermal properties. This must include the temperature change due to the near-wellbore pressure drop, which is a function of permeability and skin, that results in oil warming and gas or gassy oil cooling as a consequence of the Joule-Thomson effect.\(^6\)

The Joule-Thomson coefficient for the fluid in a particular reservoir layer is determined by employing a multiple “flash” calculation using the black-oil PVT properties of the fluid at the reservoir pressure and temperature. This calculation also determines the thermal properties of the fluid. An axisymmetric 2D radial model is then used to account for heat transfer through conduction and convection between the wellbore and casings, cement, and formation and annular well fluids; between reservoir layers and the surrounding rock; and as a function of depth. Temperature change resulting from the near-wellbore pressure drop is a function of permeability and skin. The Joule-Thomson effect accounts for this pressure drop that warms oil and cools gas and is included in the thermal model.\(^9\)

A direct measure of reservoir drawdown is thus possible using the difference between the DTS-measured temperature and the geothermal temperature in the flowing reservoir intervals. Knowing the drawdown pressure enables engineers to calculate and to monitor the effects of depletion for each reservoir layer.

Such critical information has traditionally been captured through production logs. But because acquisition of conventional logs was limited by difficult wellhead access, high flow rates and differential depletion of individual reservoirs, BP turned to a DTS system to monitor the reservoirs of the Azeri field in the Caspian Sea, offshore Azerbaijan.\(^10\)

BP engineers were particularly interested in creating efficient voltage replacement through water and gas injection, which was considered critical to reservoir drainage. The successful implementation of this strategy depended upon a direct measure of reservoir drawdown. The successful implementation of this strategy depended upon a


\(^8\) Flow from a reservoir to the wellbore is the result of pressure drop, or drawdown. This change in pressure also causes a temperature change in the flowing fluids. The change in temperature as a function of the drawdown is due to the Joule-Thomson effect. The magnitude of the change of temperature with pressure depends on the Joule-Thomson coefficient for a particular gas.


thorough understanding of production and injection conformance, both geographically and by formation. Also, because gas breakthrough was a concern, it was important to monitor the gas/oil ratio (GOR) in the producers. This is possible using DTS because an increase in GOR causes reservoir-layer fluid viscosity to decrease and the flow rate to change. These events produce a decrease in temperature that is clearly detectable through DTS.

These principles were clearly demonstrated by results from one new well in the Azeri field that flowed at 35,000 bbl/d [5,565 m³/d] with a constant GOR of 880 ft³/bbl [156.6 m³/m³]. DTS data acquired over the first four months of production clearly show temperature decreases correspond with three reservoir layers within the Pereriv reservoir into which the well was drilled (left).

Engineers built a thermal model using a core-to-log permeability correlation, reservoir intervals as defined by gamma ray log, and a skin of 4 as determined by well testing. The model was calibrated to the measured flowing well pressure by defining the reservoir layers based on the DTS measurements. Options to calibrate the model to the bottomhole pressure (BHP) measurements included significantly increasing skin to 10 or decreasing permeability by 25%. Reservoir engineers, however, decided to adjust the net to gross pay of the model reservoir layers based on the Joule-Thomson inflow intervals on the temperature profile. This created sufficient drawdown to match reservoir pressures to the BHP gauge.

The calculated Joule-Thomson temperature decrease, which resulted from the drawdown in those redefined inflowing layers, matched the DTS data. The modeled and DTS axial-flow temperatures also agreed, as did the flow distribution resulting from individual layer drawdown, permeability and skin.

After two months of production, sensors in the Pereriv B reservoir layers and in the top layers of the Pereriv D reservoir indicated increased cooling. Knowing the fluid properties—and therefore the Joule-Thomson coefficient—had not changed, the operator concluded that the only explanation for the temperature changes was a lower drawdown caused by increased depletion (left).

^ Early-time DTS data. In this plot of the DTS data, temperature decreases correspond to the reservoir layering as the fiber-optic DTS responds to the inflow of gas cooled by the Joule-Thomson effect. Temperature decreases in the Pereriv B layers (pink) are greater than those in the Pereriv D (green), indicating the drawdown in the Pereriv B is less than in Pereriv D. This difference is explained by the pressure in Pereriv B being 200 psi [1.4 MPa] lower than that in Pereriv D. A short shut-in period around 08/05/2006 is reflected in higher temperatures. (Adapted from Pinzon et al, reference 6.)

^ Time dimension. Differences in DTS readings between August (blue) and October (red) indicate inflow temperature decreases in several layers of the Pereriv B (pink stripe), C (blue stripe) and D (green stripe) reservoirs. All other parameters were unchanged, so the only explanation for the temperature shifts is depletion. The gamma ray log (black curve) was used to define intervals. (Adapted from Pinzon et al, reference 6.)
In a second new well within the field BP engineers observed a GOR increase from 1,000 to 2,500 ft³/bbl [178 to 445 m³/m³] during the first three months of production. DTS data indicated the temperature in some layers was decreasing rapidly while that in others remained unchanged. The temperature profile also clearly showed gas breakthrough in much thinner layers than would be expected from the gamma ray shale indicator. BP used the DTS-defined layering to analyze the well. To match the DTS data after gas breakthrough with the thermal model, both reservoir-layer pressure and GOR had to be changed. To achieve a unique solution, it was essential that

- modeled-layer GORs and flow match surface-achieved pressure and GOR had to be changed. To achieve a unique solution, it was essential that
- chosen reservoir pressures result in a flowing well that matches the pressure-gauge value
- within reservoir layers, calculated Joule-Thomson inflow temperature match the DTS curve
- the axial-flow temperature between reservoir layers match measured DTS data.

Engineers calculated the Joule-Thomson inflow and axial-flow temperatures and used them to compute the oil and gas flow rates of the Pereriv B and D reservoir layers. A third formation, the Pereriv C, was ignored because pressure data indicated it was impermeable. Pereriv B showed significant depletion over the three-month period while the Pereriv D showed less depletion. When the well was shut in, DTS data indicated crossflow from D into B, which was consistent with observed reservoir-layer pressure differences.

These results confirmed that gas had broken through at the top and middle of the Pereriv B and in one reservoir layer of the Pereriv D. The flow contribution after three months had also gone from 50% each from Pereriv B and D to 25% and 75%, respectively. Analysis confirmed that gas was not breaking through in a flat flood front.

Based on these results, BP gained a better understanding of layering in the Pereriv reservoir and has used this approach to review its reservoir pressure support strategy. Consequently, the company was able to reduce gas breakthrough in another well in the field using a water-injection line along the length of traditional completions. Instead, operators have typically chosen to restrict the location of electric or hydraulic instrumentation to above the packer. This has meant that the temperature of fluids from the entire lower production interval—often hundreds of meters long and comprising multiple primary production targets—is a single measurement. With so little input, determining such important factors as reservoir connectivity and compartmentalization, or how much of the perforated interval is actually contributing to production in the lower completion, may be difficult or impossible.

While Schlumberger engineers have recently deployed an opto-electric cable that incorporates an optical wet-mate connector into a North Sea subsea well, they have also developed an alternative method that is particularly suited to two-stage completions. The WellWatcher Flux system replaces hard-wire connections with a large-bore inductive coupler that provides wireless power and data communication across the upper and lower connections, allowing sensors to be placed at the reservoir section of the completion (right).

To eliminate the time-consuming need to weld splices at each sensor, engineers also designed digital temperature sensors short enough that they can be welded along a single spooled cable, or bridge. The welds are performed in a clean-room and undergo full helium-leak testing to further ensure against failure in the field. Also as a result of the spoolable system design, sensors can be tested again before installation to avoid problems arising on site. The spacing of the sensors is arbitrary but constrained by the limit of fewer than 48 sensors per 1 km [0.6 mi] of bridle.

Additionally, the sensors are miniaturized to fit on the spool. WellWatcher Flux temperature sensors have ODs of $\frac{3}{8}$ in. [19 mm] and are less than 1 ft long. This means they can be placed along sections too small to accommodate a traditional permanent sensor and its typically large-gauge mandrel. This sensor array is strapped to the production string of the lower completion, obviating the need for making connections as the upper completion is run.

WellWatcher Flux sensors use high-resolution platinum resistance thermometry to provide high-precision, low-drift measurements. The sensors’ uncalibrated accuracy is better than 0.3°C [0.5°F] at 100°C [212°F]. This accuracy was further improved during manufacturing by calibrating them to 0.1°C [0.18°F] over the range of typical reservoir temperatures.

**Wireless Connection**

Operators have placed numerous permanent temperature and pressure gauges on an electrical line along the length of traditional completions for many years. However, because of complexities already mentioned in subsea wells, permanent sensors have not been been placed in the lower section of two-stage completions. Instead, operators have typically chosen to restrict the location of electric or hydraulic instrumentation to above the packer. This has meant that the temperature of fluids from the entire lower production interval—often hundreds of meters long and comprising multiple primary production targets—is a single measurement. With so little input, determining such important factors as reservoir connectivity and compartmentalization, or how much of the perforated interval is actually contributing to production in the lower completion, may be difficult or impossible.

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11. Two conductors are referred to as inductively coupled or magnetically coupled when they are configured such that change in current flow through one wire induces a voltage across the ends of the other.


13. The uncalibrated accuracy of the sensors is better than $\pm0.8/3, or \pm0.27°C$. 

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Laboratory and in-well testing has shown minimal differences from one sensor to the next, and a standard deviation of drift of less than 0.04°C/yr [0.07°F/yr] at 125°C [257°F] (above). Field data have demonstrated 0.002°C [0.0036°F] resolution when temperature is sampled every minute. This capability to measure tiny temperature differences may make these sensors good candidates for use in interpreting thermal responses in high-angle wells where temperature change with depth is typically quite small.

In an effort to quantify zonal contribution, track depletion and identify water breakthrough, Reliance Industries Limited (RIL) installed six WellWatcher Flux permanent sandface measurement systems in its deepwater subsea development in the D1-D3 gas field in the KG-D6 block, offshore India.\(^\text{14}\) The company deployed temperature sensors on the exterior of openhole gravel-pack screens in high-rate gas wells.\(^\text{15}\)

In the world’s first such installations, RIL placed 18 to 25 sensors along the lower completion, plus two quartz gauges to update temperature and pressure measurements every second. Array temperature data were transmitted every minute and upper completion temperature and pressure data every second. The data from the dual-stage subsea wells were transmitted to shore in real time during well cleanup and the system continuously monitored the reservoir once production began.

The data combined diagnostic information with raw temperature values in packed blocks. A downhole communication hub, the WellNet multisensor station, merged those blocks with temperature and pressure data acquired above the production packer. These stations may be deployed in each production zone on gauge mandrels with power and telemetry provided by a single cable. This configuration minimizes wellhead and packer penetrations and simplifies installation.

Data transmitted from the lower to upper completion through the WellWatcher Flux inductive coupler were then transferred to a subsea interface card in the tree. The information went to an RTAC real-time acquisition and control system on the production platform, which provided real-time communication to the RIL offices in Mumbai. Engineers there were then able to use THERMA software to derive gas flow profiles from the sensor arrays.

Using the same strategy as for wells with DTS systems, analysts input the profiles into THERMA modeling and analysis software. This software performs an iterative inversion to vary reservoir properties until simulated temperature data match measured data. Standard fluid modeling programs then deliver a flow profile using those interpreted reservoir properties (left).

As the wells were cleaning up, data from the sensors were used to confirm brine displacement followed by gas flow from each of the major sand bodies. As individual wells were brought on line, Reliance engineers identified crossflow in some wells—upward flow in some wells and downward flow in others. Comparisons of when individual wells had been brought on line clearly established that the data were not just indicating crossflow between compartments within individual wells but also from one well to another.

Prompted by this evidence of connectivity, engineers added traditional interference testing


\(^\text{15}\) “Integrated Project Teams Achieve Fast-Track Conclusion at KG-D6,” in “RIL’s KG-D6 Fields—Transforming India’s Energy Landscape,” Oil & Gas Journal (Supplement, 2010), 34–38.
to the mix and used the results to update their seismic models with Petrel seismic-to-simulation software. The revised models will be used in planning future drilling operations.

**Flexibility**

Multiple permanent pressure gauges and DTS systems make powerful reservoir management tools, especially when deployed together. However, operators typically have been reluctant to use them together because to do so requires an extra penetration through packers and wellheads to accommodate both a fiber-optic cable and an electrical line. In response, Schlumberger has developed the Neon hybrid opto-electric permanent monitoring cable that allows deployment of quartz pressure gauges along with DTS in a single cable. Versions of the Neon cable have been developed to meet fluid characteristics of various downhole pressure and temperature environments. The hybrid opto-electric connectors have been qualified for continuous operations at conditions up to 103 MPa [15,000 psi] and 175°C [350°F] (right).

The ability to measure pressure and distributed temperature simultaneously is especially useful when operators are forced to drill into reservoir layers with unknown pressures, flow dynamics or permeabilities. Such was the case for one operator whose redevelopment program of a field offshore east Malaysia included completing dual-string multizone wells in deep layers. The operator had little information with which to calculate zonal allocation and depletion and wanted the ability to monitor pressure and temperature from individual zones.

Because operator engineers were also anxious to monitor gas lift performance and to identify potential leak points, sensors were installed across each reservoir perforation interval. Experts used THERMA modeling software to analyze the DTS data and then adjusted variables until measured and calculated data agreed.

The permanent system allowed uninterrupted reservoir surveillance without costly interventions and deferred production. Downhole gauge data, in conjunction with other techniques, helped determine flow from individual zones. Information about layer pressure communication was captured by wireline formation testers, well tests and pressure-transient analyses.

DTS data and analysis of zonal production in the stacked reservoir enabled early detection of internal crossflow zones during well cleanup. Zonal pressure and rate profiling helped optimize application of an inflow control valve. Further, the installation eliminated the time-consuming and often risky intervention required for cased hole logging while offering continuous wellbore data over the life of the well.

**Extracting Value**

Permanently installed pressure gauges have long been used to monitor oil and gas production. Downhole temperature sensors also have a long history, but traditionally they have been used to correct for temperature effects on measurements of pressure gauges and logging tools. However, industry acceptance of fiber-optic measurements, along with improvements in sensor reliability and interpretation capabilities, has begun to create demand for permanent temperature sensors for continuous monitoring and control of production and injection operations.

Operators are also turning to permanent DTS systems to acquire information that was previously obtainable only through production logs: detecting or monitoring fluid flow behind pipe and identifying flow from or into individual zones. Permanent DTS systems are also used with increasing frequency to identify tubing leaks as they occur and to monitor gas lift performance in artificial lift wells.

Maximizing the value of permanent downhole sensors requires operators to take a considered approach to their use. In many instances simple databases of temperature and pressure are powerful decision-making tools, useful throughout the life of a well or field. In others, realizing the full value of a sensor is contingent on its being the right tool for the circumstances, expected production problems or well architecture. For instance, in an enhanced oil recovery campaign using cyclic steam injection, the continuous measurements from permanent temperature sensors could prove critical in determining the sweep efficiency and for optimizing the timing of injection and production. The same sensor may provide valuable subsurface information about a CO₂ flood program, but if the operator’s overarching concern is pressure maintenance, a temperature gauge is not the optimal sensor.

The proliferation of permanent downhole monitoring systems has been driven in large measure by operator need to manage production from complex and remote wells. DTS and sandface pressure data allow operators to visualize what is happening in their wells and to judge the efficiency of such production strategies as artificial lift, injection and secondary-recovery programs.

But maximum value from permanent sensors is realized only when the raw data are properly interpreted. This realization plus a trend toward more multichannel systems and higher sampling rates will likely drive development of automated systems that can identify and respond to production problems with minimal human intervention.

Until that time, however, the task of interpretation and response to permanent sensor data must be the purview of experienced, knowledgeable engineers armed with appropriate software. Their interpretations, combined with other subsurface information and reservoir simulations, allow operators to take a broad, field-wide view of assets. Properly applied, the results are fewer wells drilled, more accurate well placement, fewer days spent on drilling and completion operations and, ultimately, optimal hydrocarbon recovery.

—RvF