Devon's Northridge plant can process 200 million cubic feet of natural gas per day. The plant, located in southeast Oklahoma, processes natural gas from the Arkoma Woodford shale formation.

Devon Energy Corp.

Paul E. Sanders

Fiber-Optic Sensors:

Playing Both Sides of the Energy Equation

Fiber-optic sensors are playing an emerging role in both new energy-generation technologies—including wind, solar and geothermal—and approaches for improving recovery of our existing oil and gas reserves.

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"Never before has humanity faced such a challenging outlook for energy and the planet. This can be summed up in five words: more energy, less carbon dioxide."

—Jeroen van der Veer, CEO, Royal Dutch Shell

This quote captures the challenge facing our planet's energy future. Driven by population growth and further industrial expansion, global energy demand is projected to increase an average of 1.6 percent annually over the next 25 years and to double by 2050. Although opinions vary over how to best address this challenge, almost every energy policy acknowledges that both legacy fossil fuels and new renewable energy sources will be critical to meeting the demand.

Compounding the problem, however, is the fact that oil and gas resources are becoming increasingly difficult to access and produce. Even under the most optimistic scenarios, renewable sources such as wind, solar and biofuels will not scale to relieve the escalating supply-demand tension. At the same time, we must also cope with the onset of climate change and other environmental stresses.

With the inevitable shift toward a low-carbon future, tremendous investments have been made in new energy generation and distribution technologies, which will be critical to enabling an abundant, environmentally benign global energy supply. At the same time, it will also be important to increase recovery of oil and gas resources already in decline, and to unleash the large unconventional oil and gas resource.

Fiber-optic sensors are playing an emerging role in both sides of this energy equation. They are in practical use today in both upstream and downstream segments of the oil and gas industry, and they are well suited to supporting some of the unique and varied requirements in renewable energy generation. The use of fiber-optic sensors in subsurface monitoring is especially relevant and timely in light of the challenges of our energy future, since recent upgrades have been made to the fiber-optic sensing platform. Fiber-optic sensors are now supporting the production of the large unconventional oil and gas resource, and they also have applications in emerging geothermal electrical power generation—the most scalable and lowest emission renewable energy source.

Experience has shown that it is critical to have an effective hydrogen-mitigation strategy in order to have success with any downhole fiber-optic sensing system.

Upgrading the fiber-optic sensing platform

Fiber-optic sensors were first introduced in some onshore enhanced oil-recovery pilots in the 1980s and later in the offshore oil and gas sector more than a decade ago. Since then, the technology has been improved to operate in high-temperature, hydrogen-rich environments to address the new application areas. Raman-backscatter distributed temperature sensors (DTS) have emerged as the most prevalent fiber-optic sensor product in service today. A permanently installed DTS sensing fiber encased in small-diameter stainless steel armored tubing provides a simple yet elegant sensing architecture over conventional logging tools that are periodically run in the well.

Raman DTS technology has found a niche in the oil and gas industry. These sensors are simple to implement and provide unique, real-time, full-well-bore thermal profiling. They can be used as a tool to identify and classify critical inflows and other events over time; to monitor reservoir response to process changes; and to provide insight into reservoir depletion and trends in the well over its operational lifetime. DTS has been a commercial success in service today in all regions by most major operators, and it is now available in the traditional supply chain of major oilfield services companies such as Baker Hughes, Halliburton, Schlumberger and Weatherford.

Overcoming the hydrogen problem

In any downhole application, operators must take significant measures to address the adverse effects of hydrogen, which is ubiquitous in the downhole environment due to formation chemistry and the liberation of hydrogen, the product of the galvanic reaction between well fluids and steel completion parts. Hydrogen diffusion into the fiber can induce significant light attenuation, which is especially problematic with intensity-modulated Raman DTS sensors, leading to measurement error and system failure.

DTS sensors exploit Raman scatter effects of high-intensity light launched into an optical sensing fiber. Through thermally influenced molecular vibrations from the propagating light pulse, part of the light energy is transferred, and the subsequent loss of energy increases the wavelength of light (Stokes shift), while the transferred energy can be donated to excited state atoms to decrease the wavelength (anti-Stokes shift). The amount of energy donated, and the relative intensity of anti-Stokes-shifted light, is related to the amount of atoms in an excited state—a function of temperature. In practical DTS systems, light pulses are launched into a sensing fiber and the return time and intensity of Raman backscattered signals is recorded to calculate temperature at specific locations all along the fiber to yield a fully distributed temperature sensor.

For such systems, a slight change in the ratio of Stokes to anti-Stokes intensity is used to calculate temperature. A typical scale factor is a mere 0.01 dB/°C for near-infrared pump systems. Prior to installation, one must calibrate each individual fiber because these constants will vary among different fibers, as will the intrinsic optical attenuation rate at these wavelengths ($\Delta\alpha$), which are typically 100 nm apart for 1-μm pump systems.

Once installed, the calibrated fiber must be maintained under conditions that preserve these calibration parameters.

In particular, the $\Delta\alpha$ term is prone to external influences that promote differential fiber attenuation (DFA) between the Stokes/anti-Stokes lines that will offset the calibrated $\Delta\alpha$ value and subsequent thermal measurement accuracy. In downhole DTS sensing cable systems, this requires isolating the fiber from hydrogen, as even trace amounts of hydrogen diffused into a sensing fiber creates measurement error.

Experience has shown that it is critical to have an effective hydrogen-mitigation strategy in order to have success with any downhole fiber-optic sensing system. In fact, this serves as the basis for the design of most oil and gas-sensing cables that typically incorporate hermetic hydrogen-blocking fiber coatings or cable elements. Such hermetic cables offer hydrogen protection up to 200° C to address the vast majority of conventional oil and gas wells.

However, new applications in thermal recovery and geothermal wells operate at temperatures well beyond the hermetic capability of these cables. They rely on new fiber and hydrogen compensation technology, with the premise of operation under direct hydrogen exposure. Hydrogen diffusion in optical fiber manifests into both transient and permanent attenuation in which the magnitude of the latter is dominant and highly dependent on the glass composition of the optical fiber itself.

Transient losses are reversible and caused by absorption due to dissolved hydrogen in the glass. Once hydrogen is removed, the fiber returns to its original clarity. Permanent losses are, of course, irreversible; they are caused by the chemical reactions between hydrogen and glass-precursor defects that form light-absorbing species such as hydroxyl ion with a strong absorption in the near infrared.

Hydrogen loss growth is dependent first on the hydrogen diffusion rate—a function of temperature. Initially, there is transient loss, with a magnitude governed by the hydrogen solubility in the glass. Transient loss quickly achieves equilibrium as a function of temperature and hydrogen partial pressure. From there, growth in permanent losses begins to dominate, and loss growth becomes relatively complex and difficult to predict.

Transient loss is uniform across different fiber types, as the solubility of hydrogen in the glass is independent of fiber type and achieves equilibrium once hydrogen diffusion reaches saturation.

By contrast, chemical reactions that drive permanent losses are a function of defect type; their concentration and the activation energy of bonding and valence are specific to each reaction. The type of defect and population depend on the glass composition and the subtleties of the fiber manufacturing process, which vary significantly among different fiber types.

Fortunately, the effects of hydrogen on optical fiber attenuation are well understood, and they have been mitigated by the optical telecommunications industry in undersea communications links that likewise experience hydrogen—the product of a galvanic reaction between metal cable elements and sea water. Originally developed by NTT, pure silica core fibers present a solution to reactive hydrogen-induced attenuation by reducing defect type and population. Typical permanent

Suncor Energy Inc.

Oil sand is a mixture of bitumen (a thick, sticky form of crude oil), sand, water and clay.

The role of fiber-optic sensors in monitoring oil wells and preventing spills

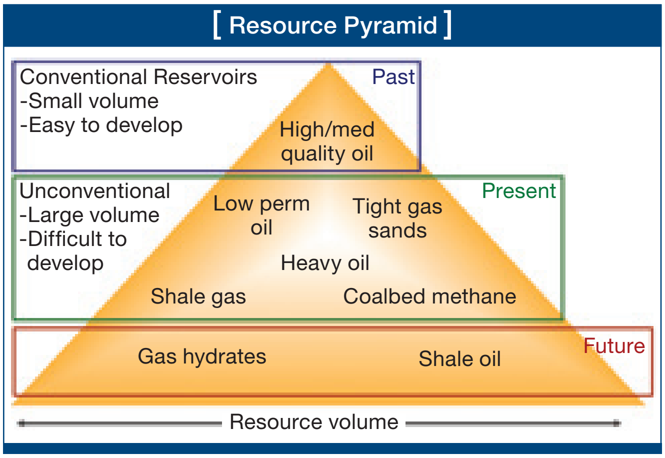
Last year, the BP Deepwater Horizon accident and oil spill on the U.S. Gulf coast provided a sobering reminder of the disastrous consequences that can accompany deep-water drilling. Could fiber-optic sensors be used to help prevent future catastrophes?

The root cause of the Deepwater Horizon incident appears to have been well integrity failure. After drilling, the initial steel pipe installed in a well is the casing, which is cemented in place and provides a seal between the well bore and the reservoir. This cement barrier is critical to preventing reservoir fluids from entering the well bore.

One of the key findings in BP's report on the cause of the accident suggests that the annulus cement barrier did not isolate the hydrocarbons. Whether this was a contributing factor to the causal chain of events has yet to be verified. However, so-called behind-casing flows between the casing and cement can have serious operational and safety consequences.

Raman DTS sensors have been evaluated for well-casing integrity monitoring. Primarily they have been used as thermal indicators for detecting the flow behind the casing—which occurs as a result of the loss of this seal or another well event that breaches the casing to cause fluid inflows. One common way to install this sensor is to suspend a sensing cable against the casing in the annulus prior to cementing. The installed and cemented DTS cables then monitor the temperature to detect any breach or fluid flow behind the casing that might create a slight temperature deviation from the natural geothermal gradient or gradual thermal excursions common during production.

With more well integrity monitoring anticipated in the offshore sector as the industry grows, fiber-optic sensors will be among the many monitoring solutions, particularly for behind-casing flow applications. They provide a permanent, continuously operated solution compared with the alternatives such a cement bonding logs and other well integrity tests that are performed periodically.



Adapted from Kuuskraa and Schmoker (1998)

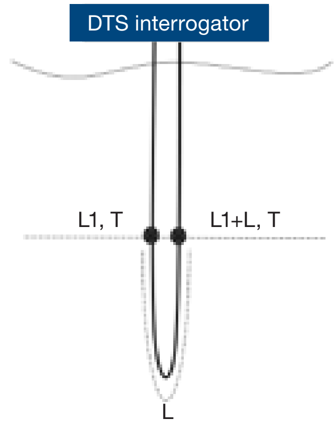
loss contribution of these fibers, if any, is isolated to hydroxyl formation. This has spurred most DTS system designers to opt for using pump lasers operating around 1 μm to avoid interference with hydroxyl absorption.

Several fiber suppliers have commercially introduced both single-mode and multimode hydrogen-tolerant fibers in a range of fiber-coating materials, including polyimide rated to 300° C and metals up to 700° C. These new ratings have spurred DTS applications in new high-temperature applications, especially in areas where conventional tools such as thermo-couples offer limited spatial resolution.

Transient hydrogen losses are limited by the solubility of hydrogen in the glass at these elevated temperatures, and this is normally accommodated within a typical system's power budget. However, transient losses are unavoidable and nonuniform, and will result in measurement error in Raman DTS by introducing DFA that offsets the calibrated $\Delta\alpha$.

The magnitude of this error can be quite significant, even for small amounts of transient hydrogen loss due to the small Stokes/anti-Stokes intensity scale factor. To mitigate this effect, dual-fiber sensing configurations and measurement protocols are used to characterize DFA along the sensing fiber, allowing for a simple mathematical correction of the calculated temperature. The most common architecture for implementing this protocol is where the sensing cable is looped and at the bottom to provide access and sensor interrogation to both ends at surface.

Two positions of the cable at common depth, separated by a distance L, are assumed to be at identical temperatures. If the cable length between the two sensing points experiences a differential loss, there will be a temperature variation between the points. This difference can then be used to compensate for the particular length of fiber between the two points and correct for the temperature difference. By understanding the DFA loss contribution, one can stitch and reconstruct the entire length of a fiber section with overlapping temperature points.



Dual-fiber sensing configuration.

The use of new hydrogen-tolerant sensing fibers and such measurement compensation methods have allowed for the upgrade of the fiber-optic sensing platform to address new applications above 200° C, notably subsurface monitoring in unconventional "heavy" oil and emerging geothermal electrical power generation.

Untapping the large unconventional oil and gas resource

According to industry predictions, in just a few years the growth in demand will outpace that of the production of easily accessible conventional oil. Much of today's global reserves are more difficult to access, geologically complex, and based on resources whose composition or other characteristics require "unconventional" means of recovery.

The pyramid above and to the left shows that unconventional fuels—of note natural gas and heavy oil available in North America—comprise the largest portion of available resources. Over the past few years, virtually all major oil companies have been aggressively adding unconventional reserves to their portfolio through leases or by acquiring pure-play producers in this sector. For example, Shell expects that natural gas will make up more than 50 percent of its global production by 2012, and much of that gas will be from unconventional reserves.

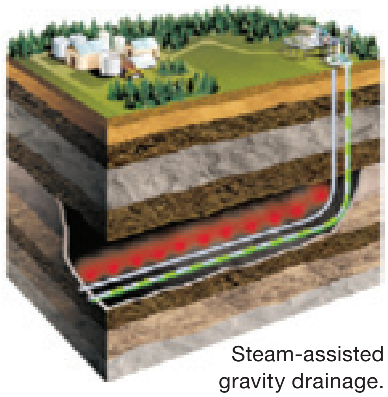
The development of these large, unconventional reserves has immediate and far-reaching benefits, especially in North America. The western Canadian oil sands account for more than 40 percent of global heavy oil reserves, with an estimated 200 billion barrels recoverable with existing technology. Today Canada is the number one exporter of oil to the United States and second only to Saudi Arabia in known reserves, mostly in the form of bitumen deposits—a thick tar-like form of petroleum, at a depth that precludes surface mining and thus requires *in situ* thermal recovery methods.

These methods are highly energy-intensive, with steam generation being the largest operating expense to recover them. With heavy oil's high exposure to production cost, there is a relentless drive by producers to achieve more efficient steam operations. A process developed in Canada called steam-assisted gravity drainage (SAGD) has quickly become the method of choice due to its more efficient steam usage and higher overall recovery compared with competing methods. It has been applied in commercial production for several years now. The majority of new *in situ* projects going forward in Alberta implement SAGD.

In the SAGD process, a pair of wells are run horizontally through the "pay zone" with steam injected into the top well to heat and mobilize the bitumen, which flows by gravity to a lower producer well and is brought to surface. High-temperature DTS systems and optical pressure gauges are being rapidly adopted by

SAGD operators to provide greater insight into the subsurface and reservoir response throughout SAGD operating phases.

DTS in particular is being used to monitor steam chamber development. It is also utilized as a process-control tool to optimize thermal conditions between injector and producer, while preventing direct steam communication between these wells; this can result in dire operational and safety consequences. The use of downhole instrumentation and fiber-optic sensing by SAGD operators is now common practice to achieve efficiencies in steaming operations and to reduce emissions and water use and improve economics and safety.



Steam-assisted gravity drainage.

Canadian Centre for Energy Information

The *in situ* sector of the oil sands in Alberta is among the most innovative and aggressive in adopting new technology in the oil and gas industry. Much of the upgrade of fiber optics for higher temperature was driven and funded by this sector. The SAGD process is just one example of the many oilfield processes and technologies pioneered in Alberta, the result of pooling of interests and resources among the industry, provincial government and universities. Alberta itself sets the benchmark for responsible stewardship of this resource; it has implemented demanding regulations for emissions; set aggressive targets for water reuse; and put in place restrictions on flaring, fresh water usage, and land access in sensitive wildlife areas.

With sensors now able to perform at high temperatures, the fiber-optic sensor platform is poised for use in geothermal electrical power generation.

For example, this sector mandates recycling and reusing more than 95 percent of its water. Cosponsored government- and industry-supported research focuses on the less energy-intensive upgrading practices of oil sands resources, new recovery technologies, and carbon capture and storage. These programs are a good example of public-private partnerships that benefit all interests by reducing operating costs and emissions. They present a model of collaboration among stakeholders and an example of how diverse resources and interests can be pooled to address the global energy challenge.

At the bottom of the resource pyramid, the vast domestic deposit of oil from shale is found mostly in the western United States, in the form of a kerogen-containing rock that can be extracted and processed into transportation fuel. It is estimated to be the source of 1.5 trillion barrels of recoverable oil—enough to sustain America's energy needs for more than a century.

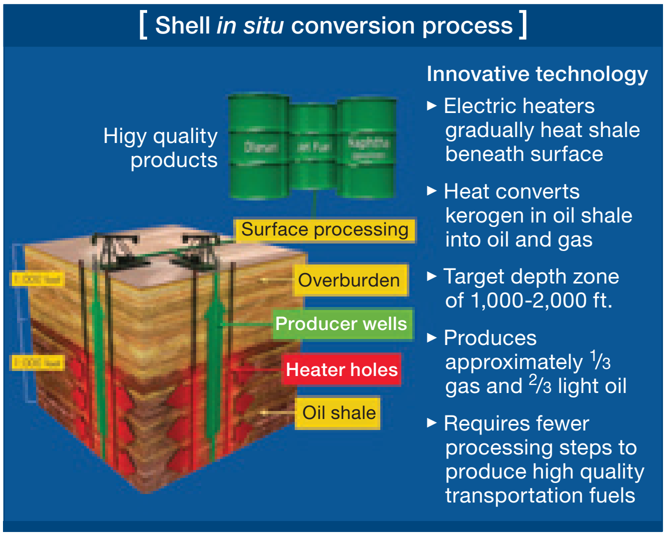
The U.S. Bureau of Land Management recently released shale oil leases to develop and demonstrate shale oil extraction on federal lands. These involve *in situ* retorting, an extraction method that heats the rock in place at depth and releases the kerogen that can be produced as a liquid and retrieved to surface. *In situ* retorting is attractive because it is less damaging to the environment than surface methods, and it does not permanently modify the land surface. High-temperature fiber-optic DTS systems are being evaluated for operation to 500° C and hotter in some of these projects.

Enhanced geothermal systems—scalable clean energy

With sensors now able to perform at high temperatures, the fiber-optic sensor platform is poised for use in geothermal electrical power generation. In a landmark study led by the Massachusetts Institute of Technology in 2006, the U.S. Department of Energy (DOE) has concluded that geothermal power generation could provide significant baseload electrical power continuously with minimal visual or environmental impact.

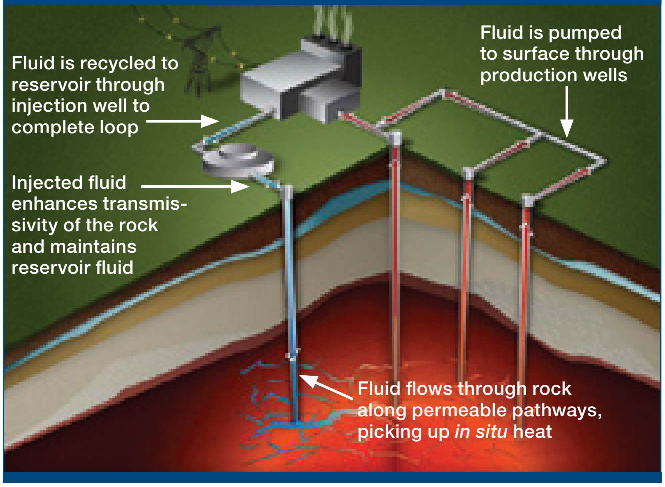
While geothermal power is currently generated using natural convective hydrothermal resources, the vast bulk of the geothermal resource is in the form of hot nonporous rock. The MIT study concluded that significant new capacity can be achieved through enhanced geothermal systems (EGS) that "enhance" the geothermal resource by hydraulically fracturing the rock to create communication between water injection and steam producer wells to drive surface generators.

According to the DOE's National Renewable Energy Laboratory, EGS opens up the possibility of generating more than 100,000 MWe of capacity on resources available in the continental United States. This represents a 40-fold increase over the current U.S. geothermal power-generating capacity.



Shell Oil

[Enhanced geothermal system]



U.S. D.O.E. Geothermal Technologies Program

EGS has recently become an important part of the DOE's renewable energy initiative, with $350 million in funding recently made available for EGS technology and demonstration. Part of this funding is directed to seven key technology development areas required for the broad implementation of EGS; high-temperature well-logging tools are among these.

The adaptation of high-temperature oil and gas logging tools appears most promising. Under this program, investigators are evaluating numerous fiber-optic sensors, including DTS, acoustic and point pressure gauges. Some of these sensors are being evaluated in pilot EGS projects in Indonesia, Australia and New Zealand as well. As in the SAGD application, this suite of sensors is being studied to provide important subsurface information through the serial operating phases of EGS. This will start with resource characterization and potential, interwell flow resistance testing, fracture diagnostics and thermal profiling of the wellbore to target injection zones for optimized water circulation and steam generation.

The overall benefits that we can expect through the use of fiber-optic sensing in EGS include validation of reservoir models and reservoir potential during site characterization, enhanced fracture and stimulation effectiveness, and improved monitoring and characterization of thermal drawdown, water injection and steam optimization during reservoir development.

Next generation multiparameter sensor systems

Fiber-optic sensors have developed a strong track record of reliability in the offshore sector, where the maximum operating temperature up to 185° C enables the use of hermetic sensing cables to deal effectively with hydrogen. The upgrade of these systems for use in SAGD and other high-temperature applications requires a system that tolerates hydrogen rather than prevents its diffusion.

A new class of hydrogen-tolerant sensing fibers and novel transient hydrogen compensation protocols have brought forward a second generation of harsh environmental systems rated to 300° C. As incremental design refinements are made, this platform can address new geothermal and electrical heater well applications up to 500° C and hotter.

Meanwhile, multiparameter sensing systems are on the horizon. With these, a single-system surface instrument and in-well sensor can simultaneously measure temperature, pressure, acoustics and other metrics. Among the first of this class is an integrated temperature and pressure system developed by LxDATA, which has been installed in operating SAGD wells to augment operation and extend the run time of electrical submersible pumps. Other multiparameter distributed temperature and acoustic systems are being evaluated in pilot systems by QOREX, which integrate Raman DTS and distributed acoustic systems based on coherent Rayleigh technology.

These systems provide an elegant architecture capable of full well bore monitoring of both parameters in real time. Through integration of both data sets over time, they present new possibilities for advanced data visualization, modeling and subsurface imaging to bring forward a next generation of fiber-optic sensors that promise to expand the application and utility of this technology—and provide an important tool to help resolve the complex energy equation.

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