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Field test of a permanent in-well fiber-optic seismic system

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ABSTRACT

A deviated borehole was drilled and completed to test systems for deployment of permanent in-well three-component fiber-optic seismic sensors. Two systems were developed and tested for deployment of these sensors. The first system involved using a passive mandrel device to enable coupling of the sensors simply using the weight of the tubing. The second system involved use of an active mandrel that incorporates a spring-loaded pad device to isolate the sensor from the tubing vibration. In addition, reference wireline vertical-seismic-profile data were acquired both in the empty cased borehole and through the tubing at the same location as the fiber optic sensor. Analysis of the data showed that best results were obtained using the active design. Tubing-related resonances were noted on data acquired using the passive design, whereas the active design did a good job of discriminating among these undesirable signals.

INTRODUCTION

Four-dimensional seismic has been shown to be a useful tool for monitoring reservoir properties such as fluid movements and pressure changes (Whitcombe et al., 2001). However, repeatability is an issue between different vintage seismic surveys, and time-lapse effects due to variations in reservoir properties can be masked or confused with other effects, such as formation compaction changes. Risks associated with 4D seismic analysis include a difficulty in separating pressure and fluid saturation effects and misinterpretations between the desired reservoir properties and other effects (such as formation compaction and changes in surface conditions such as tidal and temperature effects). Since repeatability is an issue between different vintage seismic surveys (Ronen et al., 1999; Landrø et al., 2001; Eiken et al., 2003), Landrø (1999) investigated repeatability of vertical-seismic-profile (VSP) surveys by acquiring a 3D VSP survey over a period of two days. Shot locations were reoccupied at different times during the survey, and the recorded traces from those shots were analyzed. From the similarity of the traces, Landrø concluded that 3D VSP data have an excellent degree of repeatability.

Instrumenting the wellbore downhole with three-component (3C) seismic sensors can bring several benefits:

1) Four-dimensional seismic calibration, which uses the directly recorded downhole signal to calibrate the surface seismic signal. This might best be done in conjunction with instrumented seabed seismic receivers for full-field monitoring (Jack and Thomsen, 1999) (Figure 1).
2) Four-dimensional VSP, which, with several wells instrumented, uses surface sources and downhole sensors for reservoir monitoring.
3) Microseismic monitoring; that is, passive monitoring of faulting caused by reservoir compaction and fluid fronts and active monitoring of cuttings injection and well stimulation.

Bostick (2000) showed field results of permanent emplacement of 3C fiber-optic seismic sensors. In that study, the sensors were cemented in the borehole, and the response of the fiber-optic sensors was tested. Conclusions of this first experiment were that the basic seismic attributes such as amplitude, phase, and directionality of various wave events (e.g., compressional and shear) of the fiber-optic seismic sensor data were in excellent agreement with those of conventional geophone data. Advantages of using fiber-optic-based sensors over standard (electrical) sensors are:

1) A simple and reliable design. All sensors are created using fiber, and only fiber is in the wellbore.
2) Immunity to electromagnetic interference.
3) All electronics are on the surface and can be replaced/upgraded as required.

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4) Lightweight and small-size equipment. One-inch diameter sensor packaging with current design.
5) High sensitivity and large bandwidth.
6) High channel capability per single fiber. Eight channels or more with current technology.
7) Easily implemented multiplexed or distributed sensors. Multiple sensor types (e.g., temperature, pressure, seismic) can be combined on single fibers.

We believe these attributes will result in significantly improved reliability over standard sensors. In addition, the possibility of large numbers of channels (sensors) per fiber is particularly attractive for seismic applications because large arrays of sensors [e.g., $30 \times 3C$ or more (90+ channels)] may be required for effective 3D imaging with the downhole sensors, especially in subsalt environments (Van Gestel et al., 2003).

In addition to these advantages, it is useful to mention potential issues relating to fiber-optic sensors:

1) Relative lack of track records in downhole environments.
2) Surface instrumentation may be more costly than electrical systems in the present state of the technology.
3) Certain fibers not properly protected in the presence of hydrogen can become "darkened" such that light propagation is diminished and sensor performance or interrogation may be compromised.

Of these concerns, the first will be addressed with field tests such as the one we describe, the cost of surface equipment will go down with time (in any case, our feeling is that the surface equipment costs are not a major factor), and the third can be addressed with optimized design of the cable and packaging of the sensors.

In this paper, we analyze the responses of fiber-optic sensors configured for emplacement in a production well. Two methods of conveying the sensors on the production tubing string and coupling the sensors to the borehole wall were examined. The end goal is to design a set of equipment and procedures for installation of fiber-optic sensors in production wells.

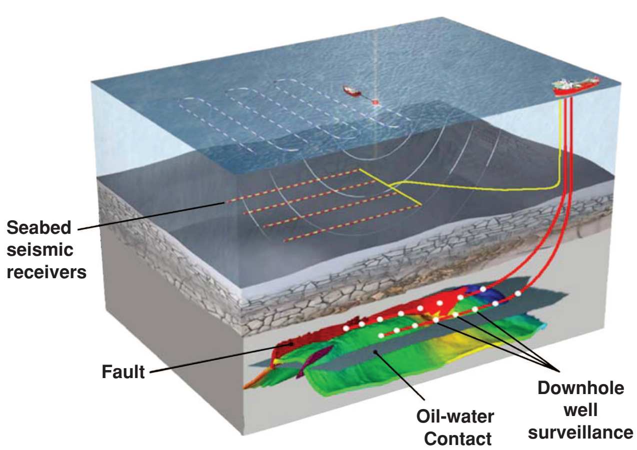

Figure 1. Illustration of an oil field with permanent seabed and downhole seismic instruments, which enable reservoir surveillance on demand.

FIBER-OPTIC SEISMIC SENSOR PRINCIPLES

Optical fibers are ultrathin strands of silicon glass with an outer diameter typically around 125 μm. They have an inner core and an outer cladding with slightly different properties such that light is guided completely within the core in many different forms, or modes. There are two basic types of fibers: multimode and single mode. Multimode fibers are used to carry separate pieces of information on different reflecting modes within the fiber core. This fiber type works well for transmitting digital data over relatively short distances of a few kilometers or less. Single-mode fibers propagate only one mode, but do so for tens of kilometers. Telecommunications use both types of optical fibers to convey the large amounts of information now used in everyday life. Both fiber types can also be used for optical sensors, and their use in industrial, medical, and military applications has been steadily increasing. More recently, optical sensors have been developed specifically for oil and gas applications. Multimode fibers allow temperature sensing along the length of the fiber, with no special transduction mechanisms or alterations to the fiber from that used in ordinary telecommunications. Single-mode fibers are also used for sensing, and they are particularly suited for high-accuracy, multiparameter, and multipoint sensing.

One type of optical sensor that is well suited for single-mode fiber is the Bragg grating. This device is created by a process in which ultraviolet (UV) light is focused on a small section (a few centimeters) of the fiber core. The optical properties of this area of the glass core are altered by the UV light. A particular pattern can be photoimprinted on the core in such a way that a specific wavelength of light is reflected from the grating while all other wavelengths are allowed to pass through. When used as a sensor, the fiber region containing the Bragg grating is strained, and the reflected wavelength shifts. The greater the strain, the larger the wavelength shift. This shift is linear since the glass itself is linearly elastic. An optical sensor, therefore, is formed by transducing the measurand into strain on the fiber at the Bragg grating. Typical parameters measured with fiber-optic Bragg gratings are pressure, temperature, strain, and vibration (Figure 2).

Fiber-optic seismic sensors, on the other hand, use a technique known as interferometry. This technique uses time delay between reflected signals from two fiber Bragg gratings. Here, the Bragg gratings are isolated from direct strain and are used as mirrors that define a sensing region. The sensing region (the interferometer) consists of a length of fiber exposed to strain (Figure 3).

Bragg gratings can allow multiple optical sensors to be combined on a single fiber. The light that passes on beyond one grating can be used to interact with other sensors, tuned to different wavelengths. This technique is known as wavelength division multiplexing (WDM) and means that multiple Bragg grating sensors or interferometers can be deployed along a fiber using only the gratings to distinguish between sensors (Figure 4). The current implementation has eight channels per fiber. Large seismic arrays are possible using multiple fibers, with three fibers incorporated in each fiber cable and multiple cables possible for each installation.

Figure 5 details a fiber-optic-based seismic sensor system based on these principles (Knudsen et al., 2003). Shown in Figure 5 is a schematic of a 16-channel instrumentation system (eight laser wavelengths and two fibers) and a compatible eight-channel optical sensor array network (Knudsen et al., 2003). The intrinsic performance of this system is very good, with total harmonic distortion (THD) and channel crossfeed along a single fiber sensor line being significantly less than 0.1%(−60 dB) and 1%(−40 dB), respectively.

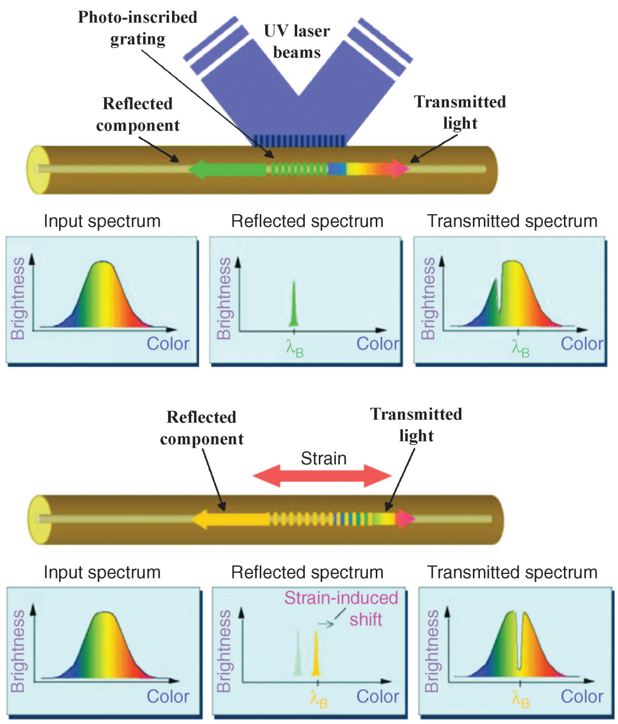

Figure 2. A Bragg grating is photoimprinted onto a small section of the core of the optical fiber using ultraviolet light, changing the property of the fiber at that location (top). This causes the fiber to reflect a very specific wavelength of light back along its length but allows all other light to pass through. When a strain is applied to the fiber location containing the grating (e.g., by changing the surrounding pressure or temperature), a different wavelength is reflected back in relation to the strain placed on the Bragg grating (bottom).

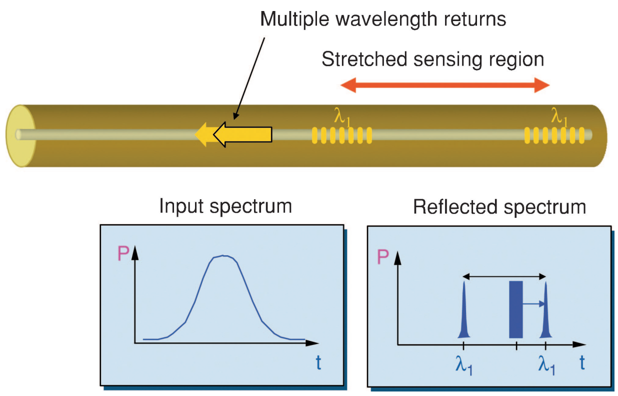

Figure 3. Fiber-optic seismic sensors use a technique known as interferometry. This technique uses time delay between reflected signals from multiple-fiber Bragg gratings. Here, the Bragg gratings are isolated from direct strain and are used as mirrors that define a sensing region. This sensing region (the interferometers) consists of a length of fiber exposed to the strain. P = power.

The fiber interferometers are configured around a proof mass to form high-fidelity miniature accelerometers. Because the annulus surrounding the production tubing and casing is limited for permanent tubing-conveyed installations in an oil/gas well, a slimline 3C-accelerometer tubular package has been designed and tested. In order to optimize sensor vector fidelity, scale factor, sensor bandwidth, and shock resistance within the packaging constraints, two different accelerometers were designed with matched performance in order to accurately measure particle acceleration in three directions with high uniformity, independent of mounting direction. One sensor was designed to measure acceleration along the longitudinal (z-axis) direction, and another radial sensor was developed to measure particle acceleration in the x- and y-directions. One longitudinal and two radial accelerometers, orthogonally configured, are used to obtain 3C measurements along a single tube. To better illustrate this, a 3C-accelerometer package with the three sensor orientations is shown in Figure 6a. In Figure 6b, the nominal frequency responses of the two accelerometer types are shown in the 10 Hz to 1.5 kHz frequency range, with each plot containing responses of five individual sensors of the same type to demonstrate their reproducibility (Knudsen et al., 2003).

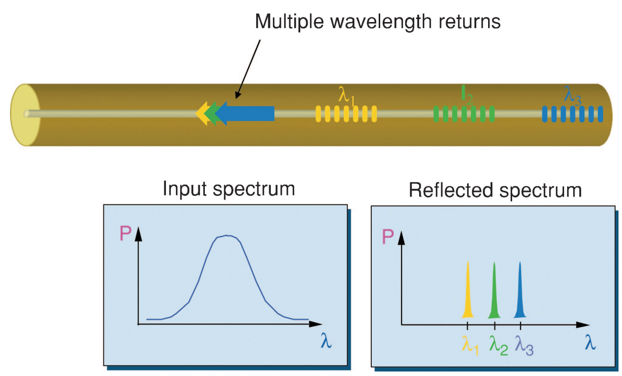

Figure 4. Multiplexing is achieved using Bragg gratings tuned to different wavelengths. Each wavelength (noninterferometric sensors) or wavelength pair (interferometric sensors) will then represent a unique sensor on the same fiber. This example shows wavelength division multiplexing for noninterferometric Bragg grating sensors. P = power.

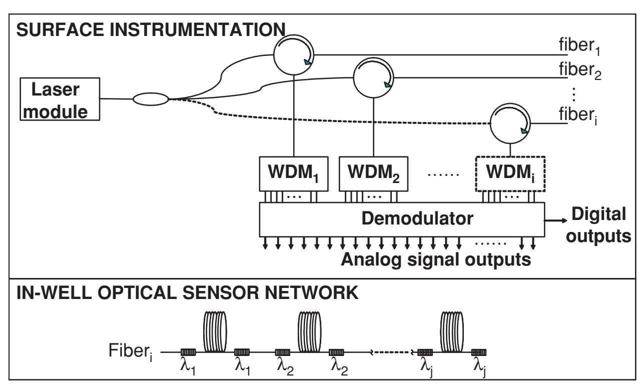

Figure 5. A 16-channel fiber-optic seismic system designed using wavelength division multiplexing (WDM) and consisting of an eight-channel laser module and optoelectronics deployed at the surface (top) and two eight-channel optical interferometer arrays in the wellbore (bottom).