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In-Well Distributed Fiber Optic Solutions for Reservoir Surveillance

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Abstract

Recently two new distributed fiber-optic sensing technologies, Distributed Acoustic Sensing (DAS) and Distributed Strain Sensing (DSS), have become available for use in oil and gas applications in addition to the more traditional temperature profiling with Distributed Temperature Sensing (DTS). These technologies offer a wide range of applications which include well integrity monitoring, gas lift optimization, flow profiling, and borehole seismic for geophysical reservoir monitoring. Fiber optic sensing can be very cost-effective in deepwater environments, where wells are exceedingly expensive and non-intrusive operations are a must to avoid very costly rig time. With a permanent fiber optic installation one may monitor, on demand, in-well pressures, temperatures, flow, and casing or completion deformation, as well away from the well using time-lapse vertical seismic profiles (VSP).

The combined interpretation of DAS, DTS, and/or DSS data allows for a more robust interpretation of flow. DAS is expected to be particularly cost-effective for geophysical surveillance in deepwater as it eliminates the need for well intervention, which often precludes down-hole monitoring altogether. Typical geophysical applications include surveillance of water injectors and propagation of waterfronts near injectors or producers.

In this paper recent field trials are discussed to demonstrate the value of these novel in-well fiber optic applications. These trials highlight the benefit of integrated data interpretation and the versatility of applications that are possible using fiber optic installations in wells. The applications shown are the use of the DSS for inflow profiling in a water injector in a deepwater asset, gas flow monitoring by combined interpretation of DAS and DTS data, and the first offshore applications of DAS for borehole seismic in Shell.

Introduction

Distributed fiber optic monitoring techniques have many advantages over conventional electrical and wireline tools for reservoir surveillance. Its distributed nature allows for having numerous individual sensing elements along a single fiber. Furthermore the technology is passive which makes it inherently safe and robust. Temperature, Pressure, Acoustic and Strain measurements can now be easily integrated into a single control line by just adding additional fibers. The combined use of these measurements offers unique opportunities for well and reservoir surveillance.

Distributed Temperature Sensing (DTS) with fiber optics is well established and offered by many vendors. DTS turns the fiber optic cable into a distributed array of temperature sensors. Over the past 15 years this technology has matured for downhole monitoring and has been applied in many oil and gas fields around the world. DTS measurements have been used with varying degrees of success for diverse applications such as injectivity profiling in water and polymer injectors, inflow profiling in oil and gas producers, gas lift performance monitoring, and monitoring the results of hydraulic fracture jobs and acid treatments.

Distributed Acoustic Sensing (DAS) is a rapidly maturing fiber optic technology with many applications for wellbore monitoring and geophysical surveillance. DAS transforms the fiber optic cable into a distributed array of acoustic sensors. Similar to DTS standard fibers can be used. Several vendors now offer DAS measurements for flow profiling and are developing geophysical monitoring applications. Shell is developing DAS technology in a partnership with OptaSense, a subsidiary of QinetiQ U.K. This collaboration has successfully developed a hydraulic frac and perforation monitoring application[1] plus geophysical applications for downhole time-lapse seismic monitoring using Vertical Seismic Profiles (VSP) [2,3]. Currently the partnership is developing tools for DAS-based flow profiling

Distributed Strain Sensing (DSS) has been developed by Shell and Baker Hughes under the product name RTCM (Real Time Compaction Monitoring).[4] By helically wrapping the optical fiber around the casing, sand screen or well tubular, three dimensional images of well deformation with a centimeter spatial resolution can be obtained. DSS on casing has been successfully installed in a Baker Hughes test well and recently the first RTCM on screen was successfully installed in an offshore well in the Gulf of Mexico.

Multiplexing a large number of low-cost pressure gauges is the first step to true Distributed Pressure Sensing. For pressure measurements several vendors commercially offer fiber optic gauges that can be densely multiplexed, until true Distributed Pressure Sensing (DPS) solutions become available. In the future time Distributed Chemical Sensing (DCS) is expected to add further monitoring capabilities with fibers that are sensitive to chemicals and can be used to distinguish between different fluids or detect toxic and corrosive elements like CO_2 and H_2S.

Combining DTS, DAS, DSS and P/T measurements in a single permanent downhole fiber optic installation offers the opportunity for on-demand measure of pressures, temperatures, acoustics, seismic and flow. That such versatility of measurements can be obtained from one system can make fiber optic sensing very cost-effective in offshore and deepwater environments where wells are exceedingly expensive and non-intrusive operations are a must to avoid costly rig time or require elimination of well intervention altogether. Permanent fiber installations also offer the opportunity to monitor in wells that cannot be accessed by conventional wireline logging tools. Another advantage of DAS and DTS technology is that these can often be retrofitted on existing fiber installations. For example DAS flow measurements can be acquired monthly or weekly using the fibers installed for the P/T gauges or DTS measurements.

Table 1 shows some examples of reservoir surveillance applications that can be implemented with a permanent fiber optic installation. For example in tight gas wells, DAS and DTS measurements can be used to measure the effectiveness of a set of hydraulic fractures. When the well starts producing DAS and DTS can be used to estimate flow where the information from P/T gauges is used as calibration points. Combined DAS and DTS interpretations of the flow are more robust than flow estimates from temperature or noise alone as the measurements offer complimentary information. For example low volume gas inflow is difficult to see on DTS measurements and maybe more easy to estimate using DAS noise logs. Another example is a fiber installation in a water injector where warmback profiling with DTS is used to monitor the outflow in each zone and where time-lapse DAS Vertical Seismic Profiles are used to monitor the flood front away from the well. In the following paragraphs we present the results of several Shell field trials showing how fibers optics can be used to implement very diverse reservoir surveillance applications and how combined interpretation of data provides more robust results and delivers additional value.

Reservoir Surveillance Application	DTS	DAS	DSS	P/T array
Flow profiling	■	■	■	■
Injectivity profiling	■	■	■	■
Artificial lift monitoring	■	■		■
Flood front monitoring	■	■		■
Fracture & perforation monitoring	■	■	▒	■
Well integrity & reservoir containment monitoring	■	■	■	■
Geophysical monitoring - Vertical Seismic profiles		■		

Table 1. A single fiber optic permanent system can be used to implement a range of reservoir surveillance applications.

Fiber-Optic flow profiling

DAS flow measurements in a tight gas well

Shell and QinetiQ have performed several field trials in tight gas wells where DAS measurements were used to provide a quantitative estimate of flow and were compared with PLT flow estimates. Figure 1 shows the results from three trials in the same unconventional gas well. In the first trial both DAS and PLT data were acquired and inflow profiles calculated. The profiles correlate very well. In the second trial the comparison was repeated three months later and a good correlation between DAS and PLT flow estimates again confirmed. After the second trial a velocity string was installed in the well which precluded another PLT run in the third trial. For this reason flow estimates were calculated using only the DAS measurements and surface rates providing a similar profile as the previous two trials.

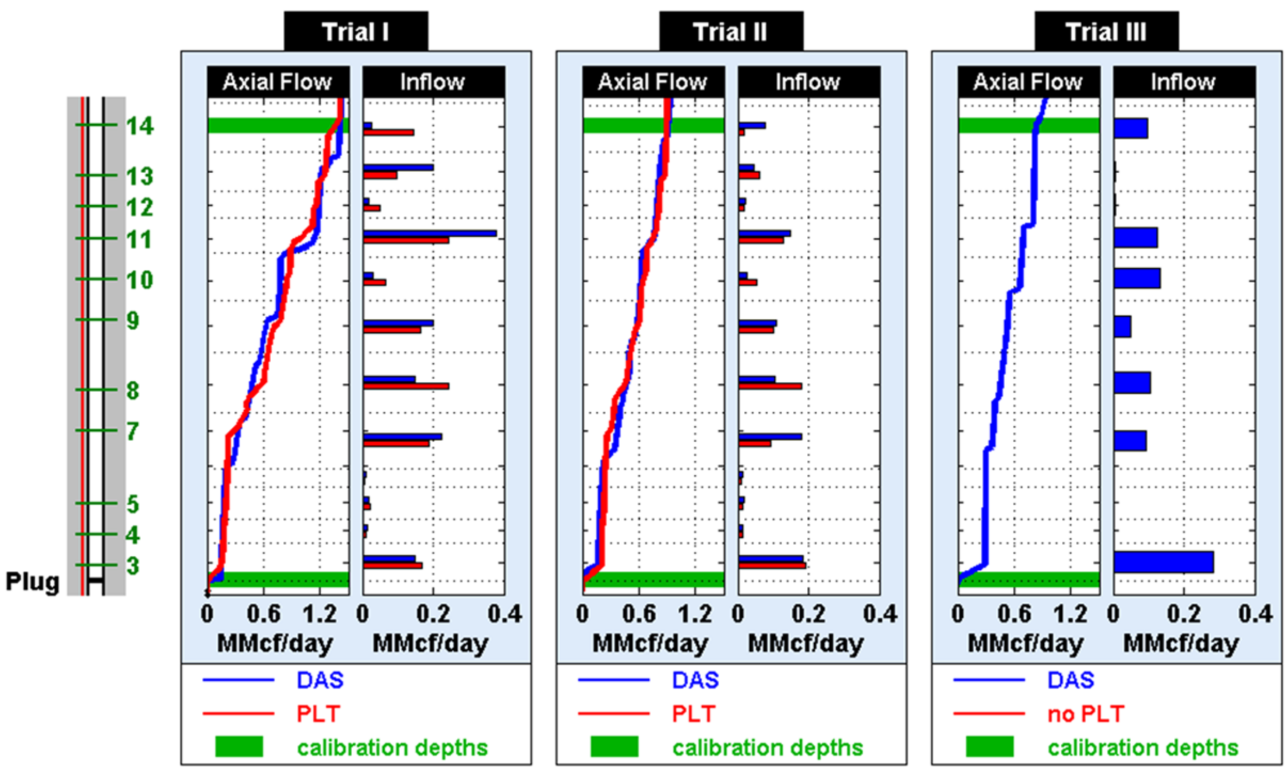

Figure 1. Estimating flow profiles in tight gas wells comparing DAS and PLT data. In trial 1 a quantitative inflow estimate was made using a DAS noise profile and compared with the PLT inflow estimate. A good correlation was obtained between the DAS and PLT estimates. This test was repeated three months later in trial 2 and again a good correlation was obtained. A velocity string precluded running the PLT in trial 3, but a flow profile could be estimated using DAS.

Monitoring water injectivity in an offshore well

A complete set of fiber-optic monitoring tools including the RTCM, DTS and point P/T gauges was deployed end 2011 in a deepwater offshore well. A fiber optic wet connect successfully mated 6 fibers on first attempt at 15,000 ft depth. This was the first time the RTCM was deployed offshore. The RTCM was deployed on 3 sand screens, with the bottom 2 running across the perforations. Figure 2 shows a snapshot of the monitoring results. The figure shows the DTS is better than the flow meter because it indicates where the water went into the formation. The RTCM adds further detail because it has beter depth control, is higher resolution, reacts faster and is directional.

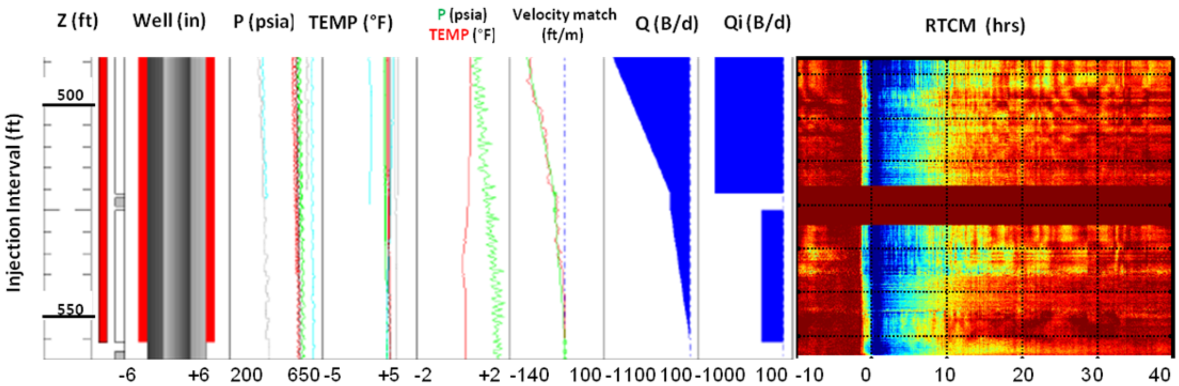

Figure 2. Example of measurements taken with an integrated fiber optic monitoring installation deployed in an offshore water injection well. The fiber installation comprises of a RTCM, DTS and point P/T gauges. DTS clearly adds value over regular flowmeter data as it indicates where the water went into the formation. The RTCM adds further detail because it has beter depth control, is higher resolution, reacts faster and is directional.

Fiber-Optic Geophysical Surveillance

DAS technology has seen rapid development for permanent geophysical monitoring. Since 2009 DAS fibers have been used in field trials in Shell in Canada, the USA, Europe and the Middle East to record Vertical Seismic Profile (VSP) surveys along the full length of the wellbore in a number of onshore wells. Zero offset, walkaway and even 3D VSP surveys were acquired using vibroseis, weight drop, airgun and dynamite sources. In several of these field trials DAS VSP results were compared with conventional geophone measurements. Figure 3 shows a of the DAS principles for the VSP application, a list of advantages, and a comparison of walkaway images. The images are essentially equivalent in terms of signal to noise ratio and resolution.

DAS VSP can also add significant value in offshore wells. In deepwater wells VSPs are often not considered because of the large cost of mobilization and deployment of the geophone tools. Not only is the mobilization of the tools expensive, but the wells need to be shut to deploy the geophone array, and often multiple tool settings are required to cover the interval of interest, resulting in a very intrusive and costly operation due to expensive rig rates. In these wells a DAS survey is very attractive because DAS records the full depth range simultaneously and no well intervention is needed. DAS can also often be retrofitted in existing fiber installations. In 2012 Shell has done two field trials offshore to test retrofitted DAS VSP with airgun sources. One of these tests was performed in a Gulf of Mexico deepwater water injector well where a DAS 3D VSP was acquired in two wells simultaneously with a 3D Ocean Bottom Node (OBN) survey. The OBN survey was already planned and was also used for the DAS survey saving overall acquisition cost. The seismic was recorded by a DAS interrogator using a spare fiber in the wells. This type of deployment opens opportunities to monitor the progress of water injection and production with time-lapse seismic. The advantage of the VSP recording in these settings is that it offers a more detailed and often less noisy image of the area near the wellbore compared to a surface seismic survey. This is particularly true in geological settings with a noisy or complex overburden.

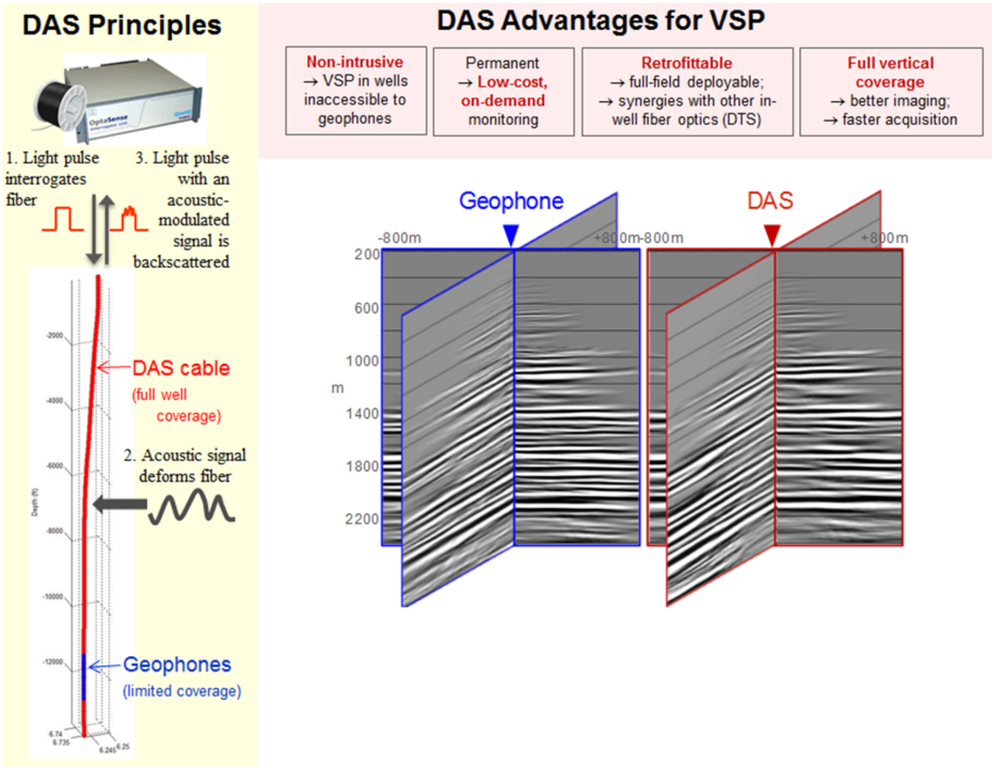

Figure 3: Schematic explanation of DAS VSP principle (left panel) showing that one may record seismic signals along an entire well at once, leading to a series of advantages (top panel) for low-cost, non-intrusive down-hole seismic monitoring. Acquired VSP data recorded on geophones and DAS are shown to result in essentially identical VSP images as shown in the bottom right panel (Mateeva et.al., SEG 2012 expanded abstracts).

Challenges

The examples in this paper show that a fiber optic permanent installation combining DTS, DAS, DSS and/or P/T measurements can deliver a diverse set of reservoir monitoring applications. Combining DTS, DAS and even DSS information can deliver injectivity and flow information and can be used for on-demand used for geophysical monitoring.

However many challenges remain including the following:

- For well performance, injectivity and flow monitoring an important challenge is the efficient interpretation of the large amounts of data provided by distributed fiber optic systems. Fit-for-purpose tools to assist or automate this task are required.
- In order to acquire meaningful injectivity or flow profiles the fiber has to be installed over the injection or production interval. This can be difficult to achieve in subsea wells or wells with liner sections. Further work is required to develop low cost deployment techniques to install fibers in these types of wells.
- Ultra high pressure deepwater and High Pressure High Temperature (HPHT) reservoirs require fibers and cables that can withstand for a long time the temperatures and pressures in these harsh environments.
- Although DAS has many advantages for geophysical monitoring the signal to noise ratio of DAS measurements stills needs to improve to match the signal to noise ratio of geophones systems. This improvement will increase the range of applicability of DAS in terms of depth of targets and time-lapse sensitivity.
- Handling of field data delivered by fiber optic systems in practical and sustainable ways has become ever more challenging. Where pressure gauges deliver a few kilobytes to a megabyte of data each day, DTS and DSS systems deliver megabytes to gigabytes, and DAS systems up to one terabyte of data per fiber per well per day. Managing these data volumes require increasingly sophisticated multi-level data processing algorithms that derive the required information for each application. It is also important that the oil and gas industry collaborates to define useful industry standards for data storage and agree appropriate data retention strategies with regulatory bodies.

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