Distributed acoustic sensing for reservoir monitoring with VSP

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3D VSP has long been viewed as conceptually attractive for illuminating targets under complex overburden, both for exploration purposes and for time-lapse monitoring of reservoirs. However, the widespread use of 3D VSP has been hindered by the cost and risk of deploying geophones in a borehole, and by the limited availability of accessible wells. These hurdles are largely removed when acquiring downhole seismic with a new measurement called distributed acoustic sensing (DAS).

Distributed acoustic sensing (DAS) utilizes a standard fiber-optic (FO) cable instead of geophones for seismic sensing along the well (Figure 1). The FO cable is interrogated by a special device on the surface, called an "interrogation unit" (IU) or "lightbox," which measures deformations along the optical fiber caused by impinging seismic waves.

DAS was first demonstrated as capable of VSP acquisition by Mestayer et al. (2011). Mestayer et al. (2012) and Mateeva et al. (2012, 2013a) showed that DAS data are already good enough to provide VSP results comparable with conventional VSP in a number of field situations (Figures 2–4). Examples of DAS data have also been published by Barberan et al. (2012), Miller et al. (2012), Parker et al. (2012, 2013), Barfoot (2013), Madsen et al. (2013), and Daley et al. (2013). A comparison between the DAS systems of various providers can be found in Hartog et al. (2013). New and improved implementations are expected with the evolution of the DAS technology.

Below, we outline DAS VSP advantages over conventional VSP with geophones, and discuss their impact on 3D VSP usability for low-cost, on-demand, seismic monitoring of reservoirs, both onshore and offshore. At the end we also

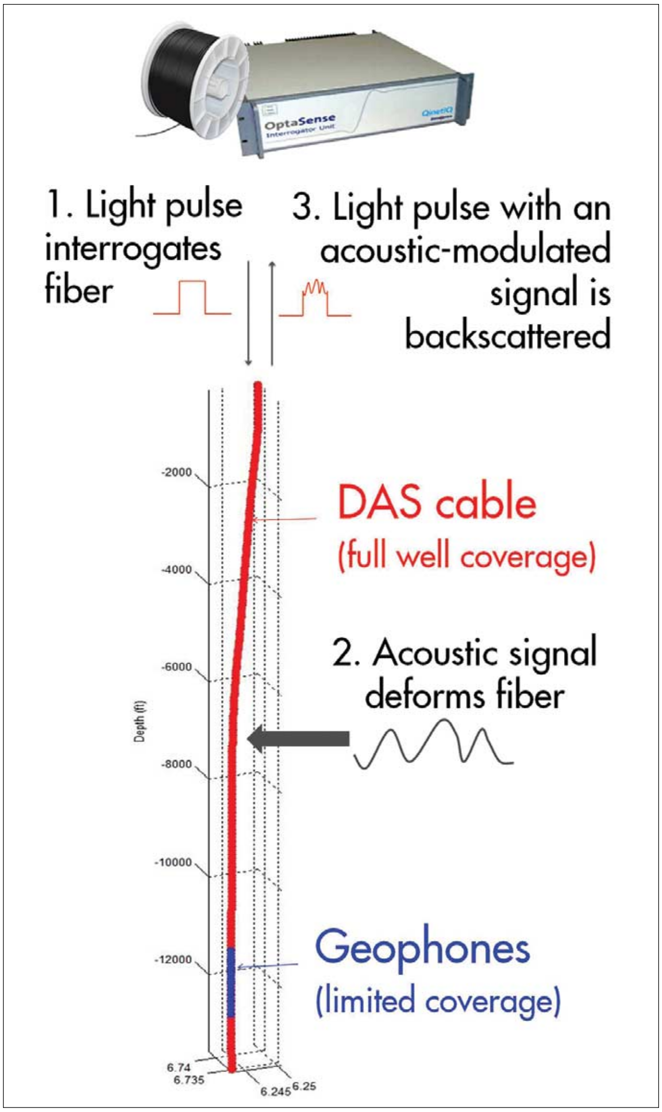

Figure 1. *Principle of VSP measurements with DAS.*

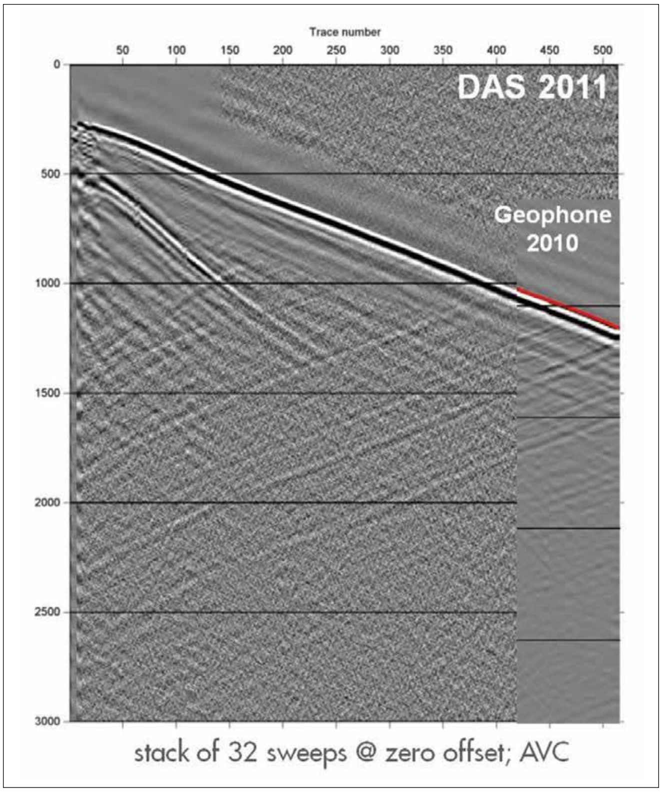

Figure 2. *A common-shot gather with DAS and geophones (insert). This example is from an onshore United States, near-vertical well, cable behind casing. Direct arrival and reflections clearly visible on both DAS and vertical geophones. S-waves are also visible on DAS in the shallow part of the well. DAS has lower signal-to-noise ratio but much larger vertical extent than the geophone array. In imaging, the additional stacking power provided by the greater number of DAS channels largely offsets the lower S/N of the raw DAS data. The first arrival on DAS is clear, with an accurate and stable waveform, allowing the extraction of a detailed check shot (Figure 3). Note that if the first arrival on DAS and geophones is assigned the same polarity, reflections on DAS have the opposite polarity of those on vertical geophones because DAS measures differential displacement, which is insensitive to the direction of wave travel (up/down).*

discuss the outstanding challenges to DAS and how those can be mitigated.

DAS advantages

Using DAS instead of geophones in a well has a number of advantages:

- *It is not intrusive.* Once an FO cable has been installed in a well (typically behind casing or on tubing), no well intervention is needed to acquire a VSP; the DAS IU is simply connected to the fiber termination at the surface. This is a significant advantage in terms of HSE, logistics, and cost, especially offshore. Cables are slim and can be deployed in most wells. Thus, DAS enables VSP in wells inaccessible to geophones, including injectors and producers.
- *Low-cost, on-demand acquisition.* With a cable permanently in place, a DAS VSP can be acquired at any time by bringing in an IU and sources. The DAS interrogation itself can cost much less than renting and deploying geophones and, thus, DAS VSP is often more affordable than a conventional VSP. The savings are particularly large offshore, because no rig time is required, and several wells can be interrogated at the same time.
- *Synergies and retrofitting.* A significant number of wells already have FO cables installed for other purposes such as distributed temperature sensing (DTS) and downhole P/T° gauges. Redundant fibers in those cables can be used for VSP, as well as for other types of DAS monitoring (noise logging, fluid-flow characterization, etc.). In uninstrumented wells, an FO cable can be installed on tubing, or even pumped inside tubing. The diverse usability of the same cable helps justify the upfront cost of its installation.
- *Full vertical coverage.* Geophone strings are often short compared to the length of a well. To achieve larger vertical coverage with geophones, one must move the string and repeat the shots, which is slow and costly (and typically

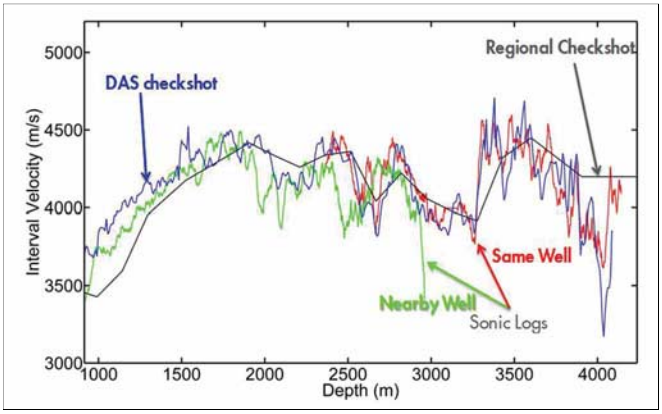

Figure 3. *DAS check shot versus sonic logs. DAS interval velocities (blue) are extracted from the data in Figure 2 by simple differentiation between consecutive DAS channels, 8 m apart (no smoothing applied). Sonic logs, smoothed to 8 m for comparison, are in excellent agreement with DAS. The deeper sonic log (red) is from the same well, while the shallower one (green) is from a well 6 km away (the nearest available) and is not expected to be a perfect match.*

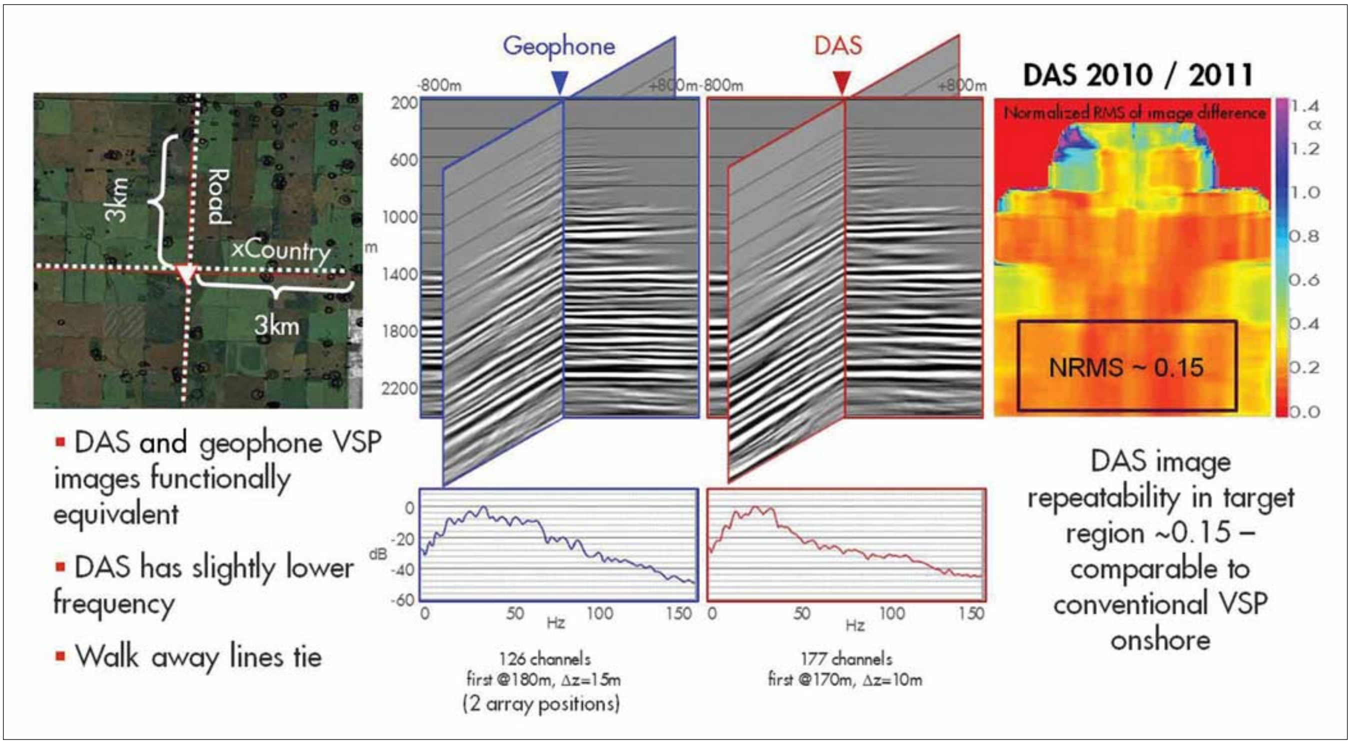

Figure 4. *DAS imaging and repeatability. This example is from an onshore Canada CO_2 capture and sequestration project. Two perpendicular walkaway lines acquired with geophones (2010) and DAS (2010, 2011) illustrate that DAS is fit-for-purpose both in terms of image quality and repeatability (no reservoir changes expected between 2010 and 2011, as CO_2 injection had not started yet). As a result, DAS VSP was put on the official monitoring, measurement and verification program.*

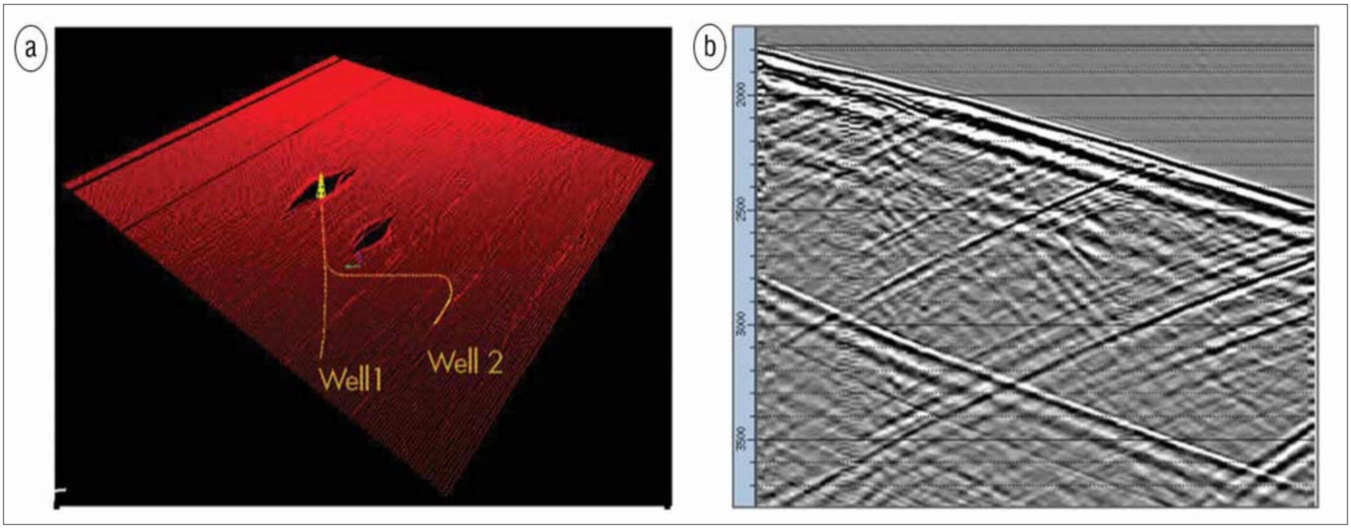

Figure 5. Dual-well 3D VSP in deep water made feasible by DAS. (a) Acquisition geometry with source points in red, receivers in yellow. (b) Raw DAS data. Near-offset shot in well 1; downgoing and reflected P-waves and PS conversions are clearly visible.

done only for 1D and 2D VSP, not 3D VSP surveys). In contrast, a DAS cable covers the entire well at once. Larger receiver coverage allows better imaging and more extensive velocity profiling.

These advantages enable a number of VSP applications that were either impractical or cost-prohibitive with geophones. Some of these are highlighted below.

Deep-water 3D/4D VSP with DAS

3D VSPs can have substantial business value in the expensive offshore environment, especially under complex overburden. But with geophones, they tend to be cost-prohibitive (rig time) and somewhat risky (if a tool gets stuck). In contrast, DAS can be acquired without any rig time or well intervention in dry-tree wells outfitted with FO cables; an IU is simply connected to the fiber-optic termination box on the platform. This allows for dramatic cost savings.

We prove the concept with a dual-well 3D VSP acquired in deep water in 2012 (Figure 5). We utilized seismic shots from a concurrent OBN campaign and pre-existing fiber optic cables (installed on tubing for unrelated purposes) to acquire ~50,000 shots into ~1400 DAS channels (about 700 per well at 8-m spacing) over the course of 7 weeks. A conventional acquisition of this scale would have been unfeasible. Moreover, these wells were inaccessible to geophones.

The obtained DAS data are of reasonable quality (Figure 5b) and can be used to calibrate velocities and de-risk the positioning of a new well. It can also serve as a baseline for time-lapse surveys. Further details on this test are given in Mateeva et al. (2013b).

Full-field monitoring with 3D VSP

DAS provides a practical opportunity to listen in many wells at the same time. This opens the door to full-field monitoring with contiguous 3D VSPs, which can be particularly useful in brown fields undergoing EOR. EOR fields are prime candidates for seismic monitoring, but their dense, changing and noisy infrastructure presents significant challenges to acquiring surface seismic. A 3D VSP is more attractive for time-lapse monitoring in these situations, but with geophones, it is difficult to upscale to cover many wells. DAS makes upscaling feasible (see Kiyashchenko et al., in this issue).

Low-footprint monitoring

Another option for monitoring injection and production in congested or environmentally sensitive areas is to use refractions to sense changes around injection and production wells. The main advantage of refractions over reflections is the low shooting effort and, thus, low surface footprint, required to sample a large area of the reservoir (Figure 6; Hansteen et al., 2010).

DAS enables downhole refraction monitoring by providing nonintrusive access to injection/production wells, unavailable to geophones, and by allowing recording in several wells simultaneously. Access to more wells means more areal coverage and higher fold for the inherently low-fold refraction survey.

DAS challenges and mitigations

While DAS has numerous and impactful advantages over geophones, it has its weaknesses, too:

- *Noisier than geophones.* The signal-to-noise ratio of raw DAS data is noticeably lower than that for geophones. Nevertheless, in a number of cases DAS VSP products (check shots, images, time-lapse images) are fit-for-purpose (Mateeva et al., 2012, 2013a). The higher noise in DAS is a limitation mainly when hunting for small signals. Usually, it can be overcome by investing in more source effort. We expect the noise floor of the DAS interrogator to be lowered significantly in the foreseeable future.

- *1C along the well.* DAS is sensitive only to axial deformations of the FO cable; it lacks broadside sensitivity. Moreover, the angular dependence of DAS is stronger than that of a geophone ($\cos^2$ versus cos of angle of incidence). That is not a major limitation for P-waves in a classical VSP geometry but it gets restrictive for strongly deviated wells in horizontally layered media. To overcome this limitation, broadside-sensitive cables are being developed (Hornman et al., 2013, Lumens et al., 2013).
- *Depth uncertainty and variation.* The position of a DAS channel is calculated by the DAS system based on the speed of light in the fiber and the time of flight of a laser pulse. However, due to the way in which fibers are deployed in a well, pinpointing the exact depth of a DAS channel with respect to geology is not trivial and requires some calibration. In addition, for single-pop impulsive sources (e.g., dynamite), the channel position has a small statistical component that may impact high-precision measurements (under investigation). This is not an issue for repeated or long-acting sources (AWD, vibrators) because that component averages out. Note that geophones are not immune to depth uncertainties either.
- *Cost of cable deployment.* The upfront cost of cable deployment is significant, especially behind casing. A less expensive alternative is to install the cable on tubing, which also allows cable replacement in case of damage. However, installations on tubing tend to be noisier and, thus, require more source effort. Therefore, the most cost-effective option for cable installation should be decided on a case-by-case basis and take into account synergies with other FO applications (noise logging, DTS, etc.)

Conclusion

Distributed acoustic sensing (DAS) is an attractive new tool for VSP acquisition. It enables a number of 3D VSP applications, especially those related to on-demand time-lapse monitoring. Cost-efficient, safe, and synergetic, DAS VSP can have a major business impact on fields undergoing IOR/EOR under complex overburden. It is usable both onshore and offshore, with particularly dramatic savings in deepwater.

The current DAS VSP technology delivers fit-for-purpose products in a variety of field situations. Its range of applicability can be expanded through further IU improvements (reduction of noise levels), cable development for broadside sensitivity, and lowering the cost of fiber-optic cable deployment. TLE

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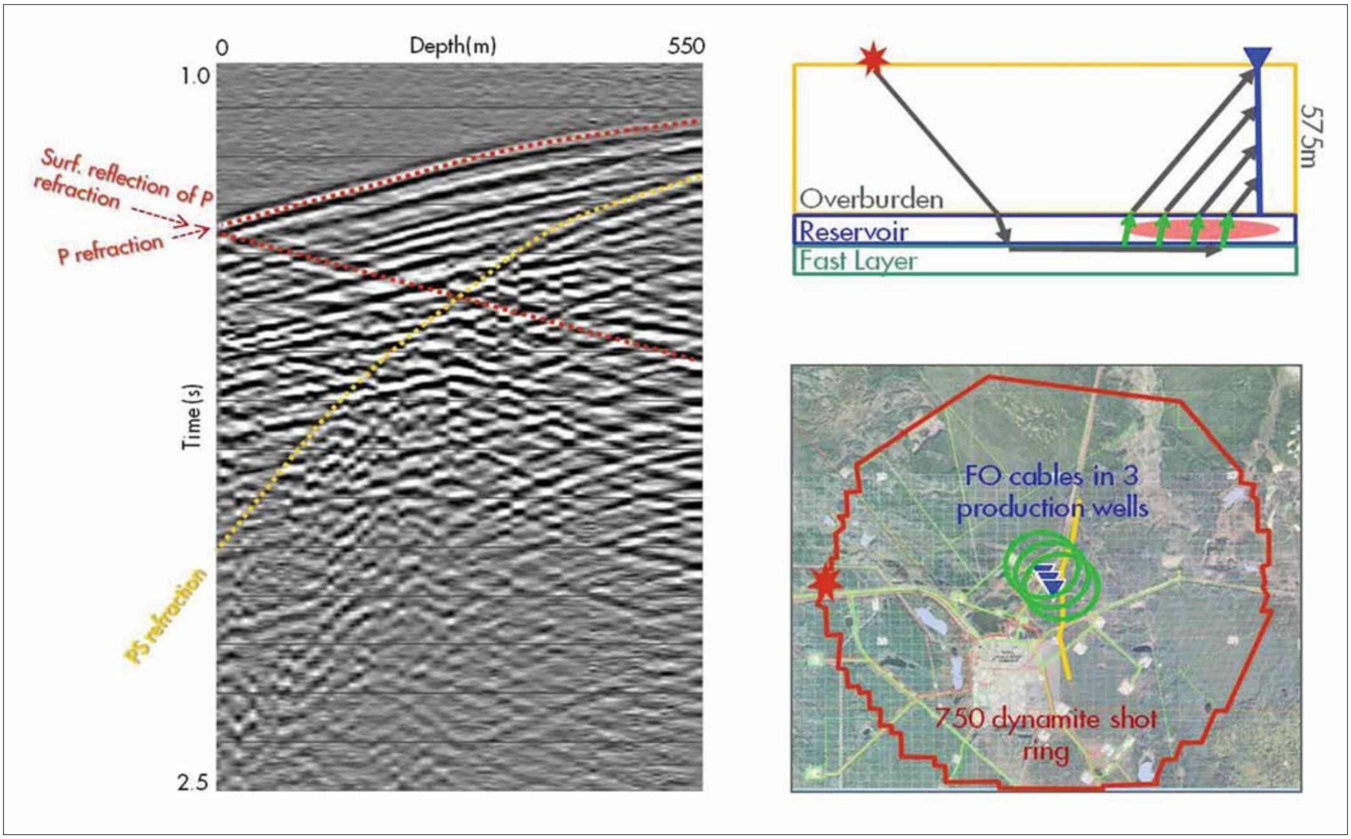

Figure 6. Refraction monitoring around injectors and producers enabled by DAS. This example is from Canada: A ring of far-offset dynamite shots was recorded with DAS in three production wells simultaneously. A rich set of refractions passing through the changing reservoir is visible in the DAS records.

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