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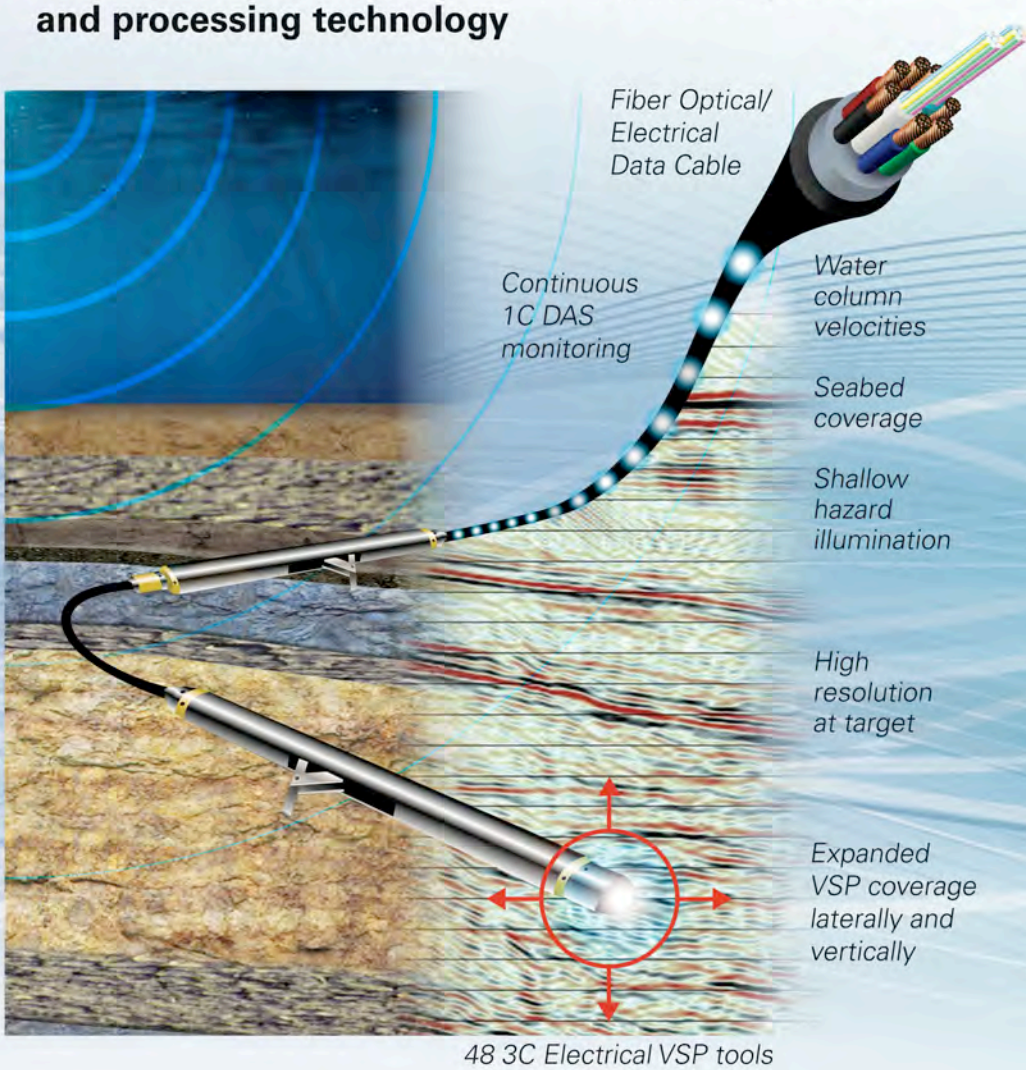

HYBRID VSP

An optimal combination of 3C geophones and fibre-optical DAS acquisition

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SUMMARY

READ is introducing a new system for VSP recording that combines 3C receivers with near-continuous DAS axial measurements. This hybrid system provides both directional information and a large image aperture, enabling the generation of high-resolution, full dip-range images for a full spatial aperture. As this would be done with only one setting of the receiver system, the savings for the client in rig-time costs can be substantial.

VSP

Seismic imaging uses a known seismic signal generated at a known location, combined with measurements of the acoustic waves scattered off a formation inhomogeneity, in order to estimate the acoustic impedance of that formation inhomogeneity. This is achieved by using an acousto-elastic wave equation, connecting the acquisition geometry with approximate knowledge of formation propagation velocities, allowing the estimations of the signal incident on a formation inhomogeneity as well as the signal scattered off that formation inhomogeneity. The acoustic impedance is then found as the ratio of these two estimated wave-field components.

Vertical Seismic Profiling (VSP) uses an acoustic source at the surface and acoustic receivers in a well close to the formation structure of interest. A receiver close to the target will record the wave field incident on the target, and – a little time later – the wave field scattered off the target. This gives formation images of greater detail and resolution, as well as more independence from detailed knowledge of the formation between the source and the receivers. Although inherent in all standard processing of VSP data, this relative independence is formalized in interferometric approach to seismic data analysis (Bakulin and Calvert, 2004).

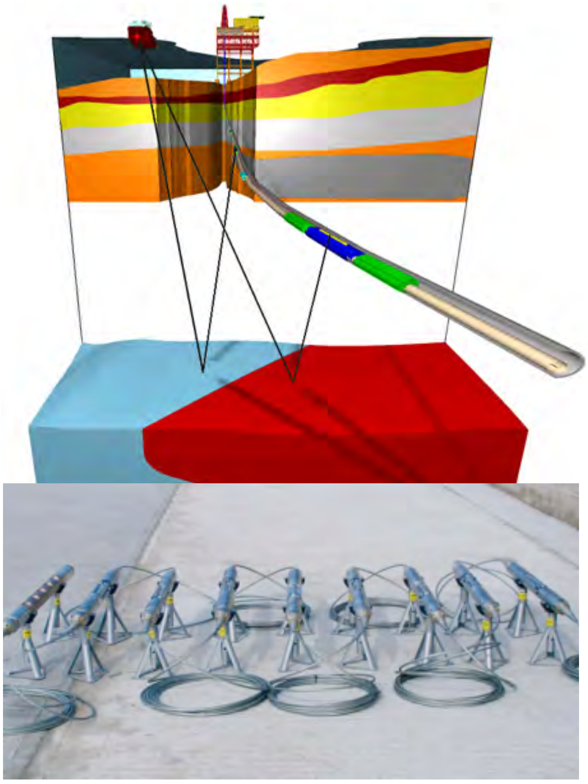

Figure 1: On the top, an illustration of the geometry used for VSP data acquisition. The well is instrumented with acoustic sensors (on the bottom).

The multi-level aspect of the receiver array will allow the estimation of delay from one receiver to the next while the wave front is passing from one end of the array to the other. The multi-level 3C receiver array can therefore be used to find estimates of both the full waveform and the direction of propagation in 3D space of any passing plane waves, arriving either directly from the source or scattered by the formation. If the formation velocities are known at some level of accuracy, the time delays and polarizations at the array of receivers are sufficient for identifying whether the passing wave was compressional or shear (Leaney and Esmersoy, 1989), the ray direction, and the distance along the ray back to the source, or the location where the compressional and shear waves coincide in time and space (e.g., Haldorsen et al., 2013).

Whereas measuring both the source and scattered fields close to the target gives formation images of higher resolution, the spatial extent of formation image becomes much smaller. To counteract this, it is desirable to combine receivers that are close to the object with receivers that are further away from the object. Adding in the requirement from wave-field measurements that one should have at-least two measurements per wavelength of the acoustic wave (this wave length is typically 30 m or 100 ft for compressional waves), one ends up wanting to deploy a rather large number of receivers. With the target at a depth of 4000 m, instrumenting the well to the surface would require 270 receivers.

Traditionally, 3D imaging with a VSP configuration has been done with 40-100 receiver levels, which typically, as a compromise, have been placed about midway between the target formation and the surface. This position gives improved resolution compared to surface seismic but not so shallow that the advantages of shorter travel paths are lost. Extent of the illumination is predicted from pre-survey modelling that attempts to answer how deep can the array be placed whilst still delivering a sufficiently large illumination area of the target.

CONVENTIONAL LARGE VSP

In many cases the information received from large VSP surveys are partly recovered by other methods such as seabed seismic and marine seismic. Lower oil prices and the demand to get more oil out of the reservoir within a shorter production period are forcing improved field economics and lower CO2 emissions. Repeated large VSPs to follow the evolution of moving fluid fronts, either produced or injected is an optimal solution if the price is right. Furthermore, permanently installed arrays mitigate safety issues by not only imaging geo-hazards in the vicinity of the well but also by permanently monitoring noise and seismic signals from the reservoir and the well itself.

Figure 2: Deploying receivers (left) and an acoustic source (right) at an offshore location.

DISTRIBUTED ACOUSTIC SENSING (DAS)

The emerging Distributed Acoustic Sensing (DAS) technology uses a simple optical fibre as the sensing element. The technology offers the capability to sample at thousands of measurement points simultaneously giving a massive acoustic sensor antenna (Farhadiroushan et al., 2009). The returned light will have a wavelength change when strain is induced at that part of the fibre, so continually monitoring the phase, amplitude and wavelength of the returned signal and using the unstrained fibre as a baseline, seismic waves interfering with the cable and inducing strain can be monitored from an optical interrogator, which is part of the surface acquisition system.

The measurement of dynamic strain in the fibre is at discreet points is similar to a single-component (1C) geophone at each point aligned in the direction of the fibre. The fibre must be continuous and any splicing has to be very high quality. The conventional electrical driven geophones are ahead of DAS sensors with respect to signal-to-noise ratio. However, recent development appears to be closing the gap (Dailey et al, 2013) and fibre-optical accelerometers are an improvement on electrical geophones. (Eick et al 2014).

However, the DAS solution is more effective, faster to operate and as it allows a massively long array. A DAS system can be used to illuminate much larger areas than a standard VSP by taking advantage of the shallow section of the antenna without compromising the benefits of having receivers closer to the target for improved resolution. Thus, DAS 'sensors' has been used to speed up VSP acquisition whilst instrumenting the entire well. Offshore rig time is costly and new methods are welcomed to reduce the use of rig time. This is particularly applicable to deep-water operations where daily rig cost is the most. It appears that the DAS technology can offer the advantage of revealing high resolution details of the reservoir combined with a large aperture image, undershooting or delimiting salt domes and gas layers or gas chimneys.

Figure 3: An acquisition box (interrogator) for a DAS system manufactured by Silixa

The DAS technology with a denser sampling can encourage the use in a large VSP of shear waves – with shorter wave length and therefore potentially better resolution (Frignet and Hartog, 2014). However, a DAS array will only measure the component of a shear or compressional mode that is parallel to the fibre. This is limitation that in certain situations may be severe (e.g., when the imaging objectives include steeply dipping formation structures).

SINGLE-COMPONENT VERSUS MULTI-COMPONENT SENSORS

The seismic waves used in the VSP survey are generated by a seismic source on the surface and recorded by receivers in the well. A three-component (3C) receivers measure three orthogonal components of particle movement generated by a wave front passing the receiver.

For each point in image space, combining the wave field polarization measured by the 3C receiver, with the space-time relationship offered by the wave equation, one may generate complete estimates of both the source field and the scattered fields over a reasonably large section of space surrounding the data acquisition site. However, as compressional and shear waves are associated with particle movements in mutually orthogonal directions, with a single-component sensor, if one may have good recordings of either the shear or the compressional components, but not of both. To get good measurements of both compressional and shear one would need a 3C sensor that simultaneously measures particle movements in all three spatial directions.

One can get decent images from vertical-components-only data, provided the geology is nearly flat, in which case the azimuth is given by the radial lines between source and each receiver. This is the product delivered by many contractors. (However, for this case, one may argue that one would not much need the VSP images.)

For more complicated geometries, with dipping structures, like, e.g., around salt domes, the reflections could conceivably be from any point on an isochron surface (isochron from Greek for "equal time"). An isochron surface is a 3D surface representing equal total travel time along a ray going from the source to a point **x** in 3D space, and then reflected to the receiver: T(source-to-**x**)+T(**x**-to-receiver) = T = constant. For a measured total travel time, the scattering point could be any point on this 3D isochron surface (for constant velocity, the isochron surface is an ellipsoid). Knowledge of the direction of the scattered ray incoming on the receiver reduces the number of possible scattering locations to two points at the intersection of the ray with the isochron surface on opposite sides of the receiver ("180° ambiguity"). To get information about the direction of the incoming ray, you need 3C receivers, and to resolve the "180° ambiguity" you need several 3C receivers.

Another concern with only using a single-component - or a DAS system giving axial-components-only and no polarization measurements - relate to the resulting reduced ability to distinguish compressional and shear waves.

Another clear advantage for 3C measurements is when the receiver array is deployed in a vertical well and the objective is to image steep structures such as the flanks of a salt dome. In this case, the scattered compressional wave field may well be polarized entirely in the horizontal plane and be completely invisible on an axial-only receiver (e.g., DAS sensors). Techniques for imaging such steep structures (Figure 4), involving reverse-time migration of 3C, vector wave fields, is described by Brooks et al. (2015).

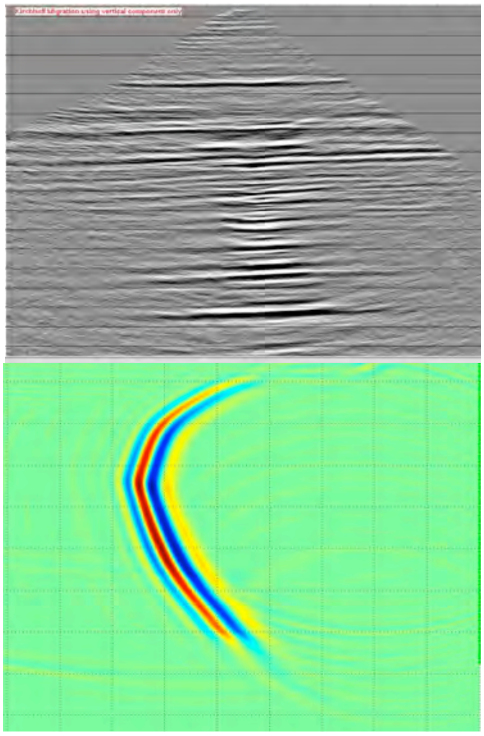

Figure 4: On the top, an image in a flat-geology region obtained from a vertical only receiver array. On the bottom, an image of an over-hanging salt flank obtained from three-component data.

ECONOMY OF LARGE-SCALE VSP SURVEYS

Typically, a large-scale VSP dataset may require around 30000 source firings and take around a week to acquire. Firing a seismic source every 10 s at 30000 different surface locations takes about 3.5 days of continuous operation, or realistically around twice this. One disadvantage of using 3C receivers is imposed by the limitations in the number of levels available in a conventional recording system. A typical recording system has the capacity of around 120 individual channels. If one uses these channels three at the time (for 3C recording), one would be limited to 40 levels. If one should want a reasonably large image aperture with 240 levels, this would require 6 settings of the receiver array, each of these settings associated with a week of data acquisition at a cost for offshore operations of typically 3-6 million USD per week at present rates of around 0.5 million USD/day.

If a well is out of production for 6 weeks for a full-aperture VSP survey, the cost in rig time alone would be prohibitive. On the other hand, the information from a carefully processed large 3D VSP could be used to significantly increase reservoir productivity and enhance the long-term recovery of hydrocarbons. Such information could also be important for better placement of development wells and injectors.

READ HYBRID RECEIVER ARRAY

READ is introducing a new system that combines 3C receivers with near-continuous DAS axial measurements (Kjos, 2013) for a 240-level array, allowing a full-scale VSP survey to be completed with only one setting of the tool.

The READ hybrid system provides both directional information and a large image aperture, enabling the generation of high-resolution, full dip-range images for a full spatial aperture. As this would be done with only one setting of the receiver system, there would be no need for repeat source coverage, and the savings for the client in rig-time costs can be substantial.

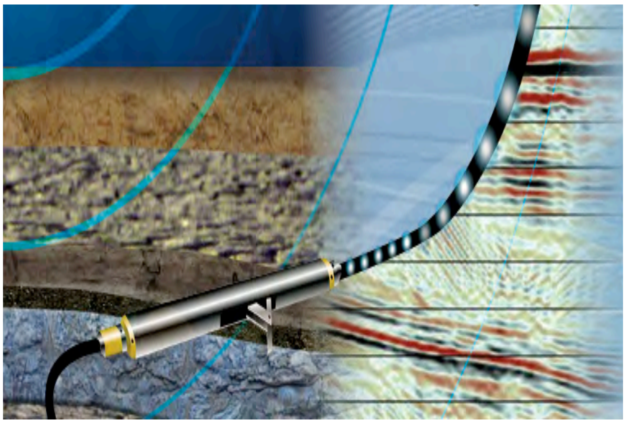

Figure 5: READ HybridVSP gives a better image of the reservoir - higher resolution, and wider aperture.

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