Joe Killen and William Wills, Avalon Sciences, discuss the requirements and delivery of seismic monitoring within extreme high pressure and temperature borehole environments.

For the last few decades, borehole seismic arrays have been used regularly by service companies to acquire high resolution seismic data across the globe. The associated technology is developing rapidly as boundaries are pushed and new plays become viable. However, in order for borehole seismic methods to continue to be fully established as an added value option, certain key technological challenges need be identified and overcome.

Borehole seismic recording traditionally involves placing geophone receivers within wellbores via a wireline (Figure 1). The advantages of such operations are well understood within the upstream industry. At its most basic, a single downhole tool can provide checkshot time to depth correlation, where straightforward analysis of the direct downgoing P-wavefield arrival can allow a much improved calibration of velocity model information for surface seismic datasets. Seismic velocity models can even be augmented further by deploying a downhole source within a neighbouring well. This cross well geometry can correct for errors derived from sonic logs recording in layers featuring significant vertical transverse isotropy (VTI).[1]

Applications of borehole seismic have gone well beyond that of velocity calibration, vertical seismic profiling (VSP) is an established technique for higher resolution imaging and mapping of subsurface layers. In comparison to surface methods, the shorter travel paths of the upgoing wavefield to the downhole receivers from a reflected horizon results in less signal attenuation whilst providing higher frequency information, thus giving a much more enhanced vertical resolution.[2] The lower noise environment downhole compared to a surface production zone also augments signal-to-noise ratio and picking accuracy. Further analysis of up waves reflected from impedance contrasts located below TD will also give some information for predicting proximal horizons ahead of the bit.

There are a range of methods for acquiring this data, depending on survey geometries and required information. Offsetting the source in various locations from the rig 'walkaway' will provide an increased aperture and penetration into the formation, whilst shot points located vertically incident to the well 'walk above' will facilitate very high resolution upwave reflections of formations located just below the deviated well azimuth. More intricate surveys with spiralling source positions away 'walk around' from the well head and rerecorded over several months can add significant value to an exploration target through delivering 3D and event time-lapse (4D) seismic plots with much analysis dependant on the horizontal components HXHY of the downhole 3-C sensor pack.

Figure 1. *Downhole geophones with locking arm to couple to formations/casing.*

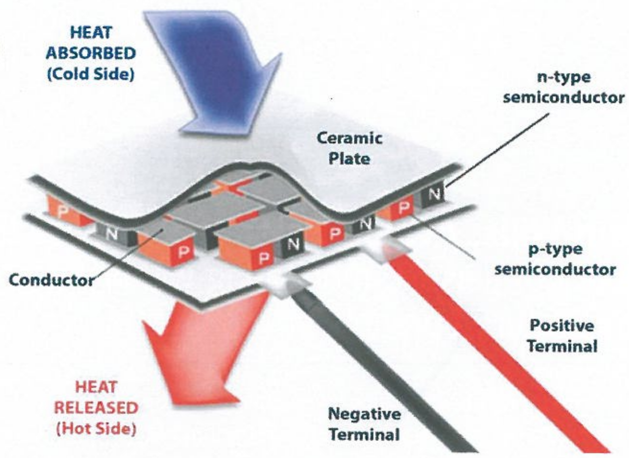

Figure 2. *Schematic of a thermoelectical cooler (TEC).*

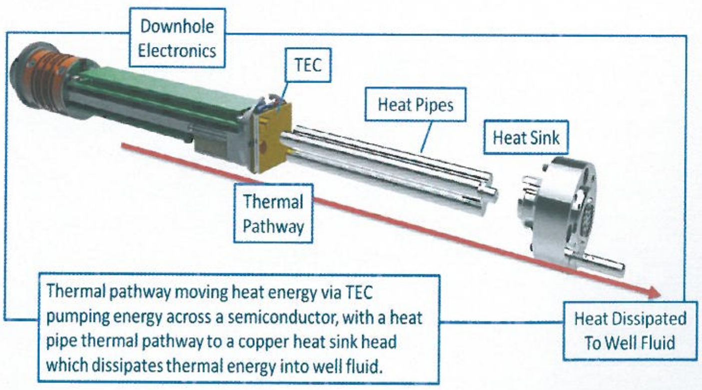

Figure 3. *Schematic showing the thermal pathway and temperature management system of downhole electronics.*

In contrast to VSP surveys, microseismic monitoring involves passive monitoring of relatively low magnitude (M_w <2) events, often those generated during the process of hydraulic fracturing of high porosity, low permeability plays such as shales and tight sands, using water/sand/chemical proppant under extreme pressure in order to allow a pathway for gas extraction. Accurate time picking and velocity modelling is required in order to locate the microseismic hypocentres. The use of three component downhole sensors have advantages over surface seismic monitoring in terms of noise reduction, immunity to distortion of unconsolidated weathering layers, as well as depth correlation. This all allows for a reduced uncertainty in both the location and nature of the frack event foci and so improved estimation of stimulated reservoir volume (SRV). Despite all these advantages, new exploration frontiers are meaning the demands placed on downhole seismic equipment are ever increasing.

The demand: pressure, temperature, sensitivity

With the current stagnation in the global economy and tightening of exploration expenditure, borehole hardware must continue its adaptability and respond to industry trends if it is to stay current and relevant. As conventional reserves are dwindling, operators are looking towards deepwater and uncharted areas for new plays. As a result service companies are increasingly being asked to work in deeper, higher pressure, higher temperature reservoir zones. HPHT production well technology has been available for many years, capable of dealing with pressures in excess of 20 000 psi (1379 bar) and temperatures greater than 266 °F (130 °C). Until recently borehole seismic technology has been limited to this range ~302 °F (150 °C), and 25 000 psi (1724 bar) due to hardware milestones. However, in order to keep pace with the rest of the industry and maintain its relevance as a key component of upstream exploration, downhole technology has begun to make breakthroughs to operate at ultra-high pressures (30 kpsi+) and temperatures 356 °F (180 °C+) whilst still providing the gain step advantage in sensitivity and signal to noise expected of boreholes seismic over surface methods.

An example of image zones that present such technological challenges is the deep sounding undeformed reflectors of the Tertiary Wilcox Trend situated within the deepwater Gulf of Mexico (GoM). Here, the combination of high pressure and temperatures due to large water depths, deep reservoirs, and complex overlying salt layers present considerable problems to the exploration industry. Salt canopies up to 20 000 ft (6000 m) thick and covering approximately 90% of the trend[3] have proven very difficult for standard surface seismic surveys. Despite advances in wide azimuth (WAZ) surface seismic surveying and prestack depth migration method (PSDM) poor vertical resolution due to a combination of salt layer geometry, multiple generation above salt layers, low amplitude first arrivals and distortion from weathering layers, often result in relatively poor velocity models unable to accurately image deep reservoirs.[4] By augmenting surface data with 3D VSP information obtained with the use of three component receivers located proximal to or beneath the salt canopy, the industry has found potential to not only improve first arrival signal-to-noise, and they are also less subject to wavefield distortion and regional anisotropy.

Current economic conditions and prices have forced emphasis to be placed on efficiency of systems and reduce rig downtime by ensuring VSP survey time is reduced to a minimum. By using long arrays or permanent seismic recording systems,

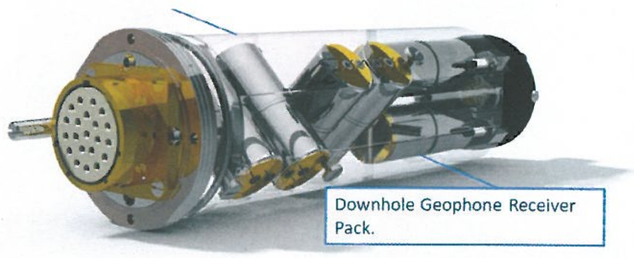

Figure 4. *Downhole 'Quad' geophone receiver pack with four geophones per axis wired in series. Signal is multiplied by the number of connected geophones when wired in series.*

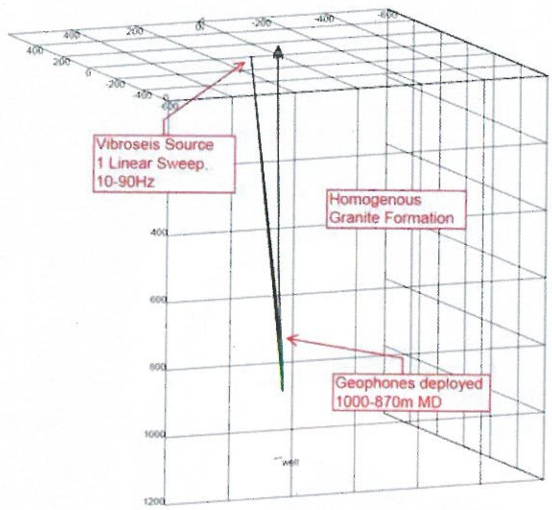

Figure 5. *RH12 Well view of ZO VSP at ASL Cornwall Rosemanowes (UK). 'Quad' and 'Dual' geophones were deployed in the shallow section (850 - 1000 m TVD). Single vibroseis sweeps were performed for each sensor pack type.*

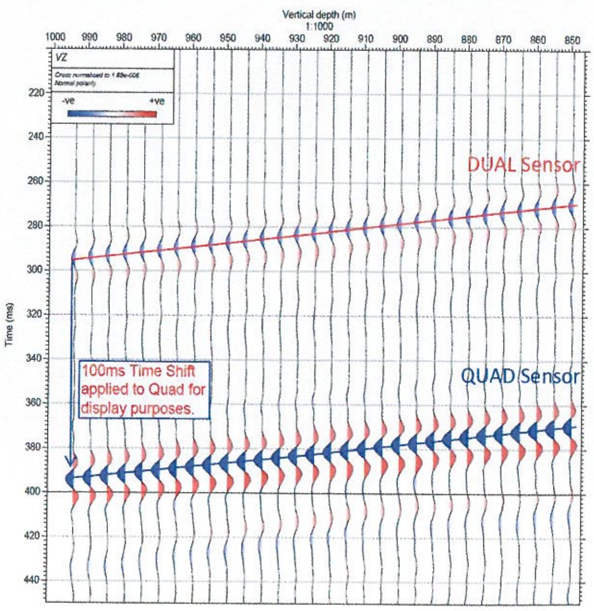

Figure 6. *Time domain comparison of first arrivals of 'Dual' sensor pack versus 'Quad' sensor pack shows a significant difference in sensitivity. First arrival signal amplitude on the 'Quad' sensor is 6 dB (x2) that recorded on the 'Dual' sensor pack (100 ms time shift has been applied to 'Quad' pack for display purposes).*

it is possible to undertake 3D VSP surveys and surface seismic surveys simultaneously. Such concurrent surveys are attractive to service companies and operators, especially when such acquisition is associated with the high cost of drilling deepwater wells and the challenges associated with their re-entry. This has led to time-lapse seismic surveys (4D) being seen as the next significant seismic technique to be applied routinely in the deepwater GoM. The method can be applied to characterise reservoir properties, monitor production efficiency, and estimate volumetric from inception through the life of the field.[5]

Temperature and pressure are not the only demands placed on a downhole seismic system. The boom over the last 10 years in exploration and production of unconventional reserves has been celebrated by many across the globe, however public scepticism of heavy oil, subsalt plays and shale oil and gas has meant governments are enforcing stricter regulations and demanding more stringent monitoring of reservoirs, especially in more populated areas. As a result, a new market is growing for the provision of high sensitivity instrumentation to be a key provider in enforced reservoir monitoring of low amplitude frack-generated microseismicity.

Meeting the challenge

The major difficulties surrounding ultra high temperature wells are cooling issues associated with electronics. Strides in development in insulation and active cooling have meant operating temperature limits are continuously being pushed. The latest innovations in temperature management of down-hole electronics consist of various techniques including vacuum insulation, heat pipes, phase change media and thermo-electric cooling (TEC).[6] These so far have allowed continuous digital operation at 356˚F (180˚C). TECs are solid state heat pumps that transfer heat. TECs contain two semiconductors connected by a thermally conducting plate on either side. A Peltier effect is generated where once a DC current is applied, a temperature difference is induced at the boundary of the semiconductors. Heat is transferred from one side of the TEC to the other (Figure 2).

The advantage of using solid state TECs compared to conventional refrigerator/radiator technology is the lack of moving parts and the minimisation of noise applied to the geophone receivers. Such refrigerant components are thus often used in production environments such as logging/seismic logging while drilling.[6]

To improve the efficiency of heat transfer away from the TEC, heat pipes can be utilised (Figure 3). Heat pipe technology works by relying on release of latent heat during phase change of water inside a heat pipe. At the hot end of the heat pipe, the liquid is turned into a vapour, and rises to the cold interface where it condenses to a liquid and releases latent heat. The liquid is then cycled to the hot interface by either a wick, or by gravity. Heat pipes can be extremely efficient and the very high rate of thermal transport in a small area makes them perfect for transport of heat.

Insulation of electronics is a key component of thermal management. The challenge associated with insulation is to limit conduction pathways. Manufacturers deliver this by vacuum flasking temperature sensitive printed circuit boards. High precision fabrication such as electron beam welding is required to ensure vacuum fidelity.

High pressure instrumentation is dependent on robust seals and electronic feed throughs. Downhole tools are evolving to replace conventional o-ring seals with metal-metal seals. This not only delivers a higher pressure rating but is much more resistant to aggressive borehole substances such as H_2S. These extra high pressure seals employ metal C rings which are fitted and emplaced under specific torque settings providing a 30 000 + psi pressure rating. The metal-metal seal principle is based on the plastic and elastic deformation of the c ring during compression which creates a seal capable of not only withstanding ultra high pressures but for long durations. This has the 'dual' benefit of low maintenance costs coupled with reduced rig downtime.

Geophone receiver improvements

Geophone sensitivity is an often overlooked hardware property for accurately defining arrival time picks in low signal to noise (S/N) environments commonly associated with large offsets, microseismicity and proximity to production wells. With the use of passive transducers (Figure 4) signal is multiplied by the number of connected geophones when wired in series with local thermal noise increasing at a much smaller rate. This can therefore add much value when such sensor packs are deployed within high temperature well environments.

Testing at the Rosemanowes Deep Well test facility (Figure 5) has been undertaken to compare amplitude signal to noise of 'Dual' Geophone receivers containing two geophones per axis, and 'Quad' geophone receivers containing four geophones per axis within an ASR downhole satellite.

Comparison of the two systems shows a significant difference in sensitivity between sensor pack types (Figure 6). Not only is first arrival signal amplitude considerably greater for 'Quad' sensor pack receivers, analysis of the pick amplitude ratio to RMS noise (Figure 7) shows an average of 6 dB improvement when doubling the number of phone elements. It should be noted thermal noise (Johnson-Nyquist noise) can have an impact on sensitivity, especially during operations in hot well conditions. The increased coil resistance due to higher temperature results in greater thermal noise of the system and therefore affects the geophone sensitivity. It is in well environments such as this that quad geophone receivers will give better S/N improvements compared to dual receivers as signal is doubled, whilst only featuring a marginal increase in thermal noise (Figure 8).

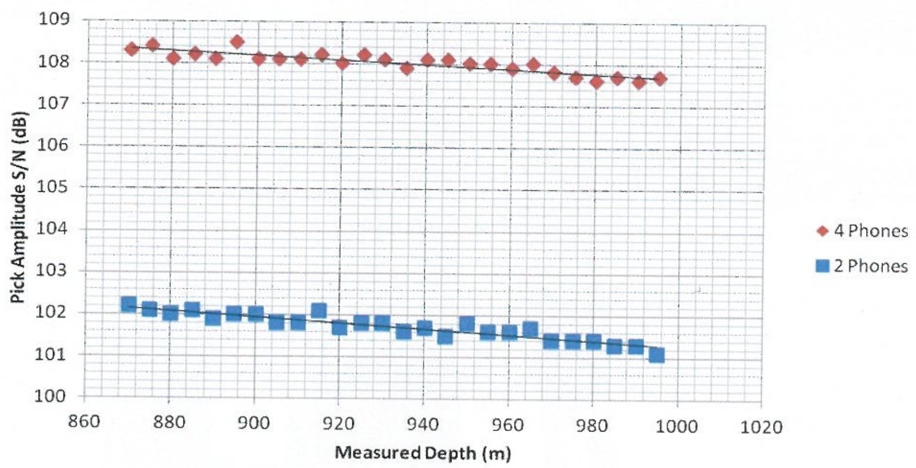

***Figure 7.** Downhole Testing – two and four element signal pick amplitude to RMS noise ratio (S/N) performance plotted against depth. Ratio of pick amplitude to RMS noise amplitude.*

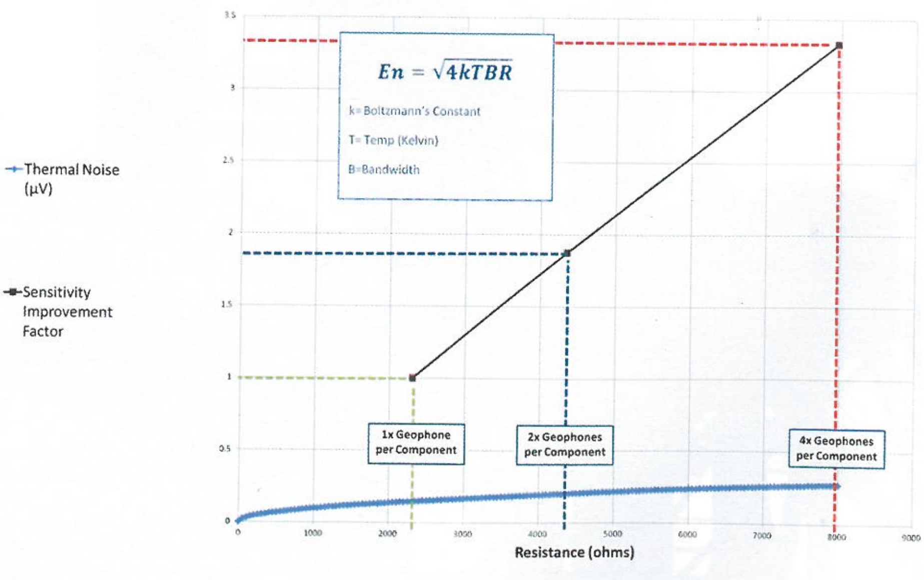

***Figure 8.** Thermal noise (Johnson-Nyquist Noise) and SMC 2400 geophone sensitivity versus coil resistance at 302 °F (150 °C).*

Harder, better, faster, stronger

Borehole seismic technology is making vast technological leaps in its efforts to provide the latest market for continuous operation in increasingly hostile well environments. Manufacturers and service providers alike must remain flexible and maintain their ability to move with industry requirements, as well as predicting and preparing for future trends. The future potential of fibre optic and distributed acoustic sensing will also be ever an increasingly complimentary technology. Pushing tool longevity and sensitivity capabilities remains as important as ever for both the presently cautions seismic exploration market and growing regulation driven market for semi/permanent monitoring.

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