Reservoir Geoscience

Passive seismic makes sense for 4D reservoir monitoring

Stephen Wilson¹, Rob Jones, Will Wason, Daniel Raymer and Paul Jaques of Vetco Gray, Cornwall, UK (formerly part of ABB) describe how passive seismic monitoring technology is making its way into the mainstream as a value proposition for the management of hydrocarbon resources.

The use of 4D seismic as a mainstream technology in the management of hydrocarbon reservoirs is now established. In contrast to the traditional perception of seismic technology as an exploration tool, the value of 4D seismic sits securely on the production side of oilfield technology. This shift in emphasis within the seismic industry to encompass both production and exploration work has recently taken on a higher profile as a result of the difficulty of increasing reserves purely by exploration. New production technology now offers an alternative path to increasing booked reserves.

The widening scope of seismic applications and the increasing number of reservoir geophysicists is helping to bring forward another seismic technology capable of greatly improving our understanding of reservoir dynamics. That technology is passive seismic monitoring. During the past few years the implementation of passive seismic monitoring as a mainstream technology for the management of hydrocarbon resources has been gathering pace. Recent permanent passive seismic studies in Oman have shown the capabilities of this technology to provide information upon which reservoir management decisions can be made (Jones et al, 2004).

Knowledge of the existence and capabilities of the technology within our industry is reaching a critical mass and the technological barriers to its uptake are disappearing. Perhaps the most critical of these barriers concerns the ability to monitor microseismic activity from within active wells during production or injection. Recent developments in downhole tool technology allow the deployment of downhole seismic sensors capable of a 30-40 db improvement in signal performance when compared with previous technologies (Jaques et al., 2003).

In addition to improvements in tool technology, software applications capable of delivering automatic microseismic locations to the client’s desktop in real-time are now available (Jones and Wason, 2004).

The advent of 4D has improved our ability to observe reservoir performance and make timely decisions about reservoir operations. The deployment of permanent ocean bottom systems provides scope for improving the speed with which reservoir management decisions can be made by reducing turnaround time. Passive seismic monitoring further supports this improved decision-making capability by delivering real-time information about the reservoir to the desktop within minutes.

In terms of instrumentation, permanent downhole seismic sensors represent the cornerstone for the implementation of full-field continuous passive seismic monitoring. The prospect of permanent downhole seismic sensors for use during 4D studies offers the prospect of accurate well ties, wavelet characterisation and VSP on demand. The combined value proposition for passive seismic monitoring and 4D seismic using downhole instrumentation may now be sufficient to drive the deployment of these systems.

Figure 1 illustrates this virtuous circle of 4D seismic promoting the take up of microseismic technology which in turn helps 4D to better resolve reservoir change. All of which is driven by the value proposition of new technology as a method of improving recovery, increasing NPV and booking reserves.

Passive seismic monitoring: what can it tell you?

Hydrocarbon reservoirs support anisotropic earth stresses that under normal conditions lock together the naturally occurring fractures in the subsurface. The production of Figure 1 Virtuous circle

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A high quality microseismic dataset can provide information about reservoir behaviour, such as:

- Identification of hydraulically conductive fault structures acting as flow channels for water breakthrough
- Identification of sealing faults which can affect pressure maintenance and result in reservoir compartmentalisation and bypassed zones
- Image flow anisotropy associated with production from fractured reservoirs
- Continuous 4D monitoring of fluid pressure front movement, such as water flood fronts and hydrofrac operations
- Continuous 4D monitoring of disposal operations such as drill cuttings, CO2 or sour gas injection
- Identification of seismically active zones

Knowledge gained from the above can help the operator identify areas of the reservoir that are:

- Supported or unsupported by pressure maintenance
- Represent a drilling risk (i.e. seismically active fault structures)
- Undergoing compaction processes
- Suffering cap rock integrity issues

This information about the dynamic state of the reservoir allows the operator to better manage production/injection processes including the targeting of new production/injection wells.

The use of microseismic location data is only part of the story. Once these shear sources are located, one can start to use them to image reservoir structure to determine reservoir anisotropy, to constrain geomechanical reservoir models, and to provide input to reservoir flow models. A few examples from the microseismic literature illustrating some of these capabilities are referenced later in this paper.

Data acquisition and instrumentation

The installation of permanent downhole monitoring systems is seen as critical to realising the full benefit of passive seismic monitoring. In contrast to reflection seismology that takes a snapshot of impedance contrasts in an imaged volume, microseismic technology records the discrete acoustic signals generated by shear movements in the monitored volume. To record all the microseismic signals it is necessary to monitor continuously, triggering and extracting each microseismic event from the incoming data stream as it happens.

In addition to continuous monitoring, realising the full benefit of the microseismic technique requires that the sensors are placed downhole. The reason for this requirement stems from the magnitude statistics of microseismic data, signal attenuation and high noise levels close to the surface.

Magnitude statistics of microseismic events show a power law distribution. The smaller the event the more numerous they are. Thus, within a given rock volume over a set time period, it might be possible to record 10 magnitude zero events. Within the same rock volume and time period there could be as many as 10³ events with magnitude minus three or above.

By placing seismic sensors in the subsurface these small but numerous magnitude minus three events emit enough energy to propagate across the reservoir volume whilst maintaining sufficient amplitude to appear above the noise floor in this quiet downhole environment. However, in order to reach the surface, these microseismic signals have to fight their way up through the stratigraphy losing energy as they cross each interface. Finally, as they approach the surface, they have to cross the highly attenuating weathered layer before finally reaching any surface sensors. These highly attenuated signals can then find that any sign of their presence has been swamped by the high noise levels characteristic of the surface environment.

Comparison of recorded event rate and location uncertainty between datasets recorded from surface seismic instrumentation (Al-Mahrooqi et al. 2004) when compared with studies using downhole instrumentation (Jones et al. 2004) show how important it is to use seismic systems deployed in a quiet downhole environment.

Another noise contamination problem manifests itself in noisy production or injection wells where the noise level precludes the recording of all microseismic data except the very largest and most infrequent of events. In order to record high quality microseismic datasets, bespoke monitoring wells were previously the only solution to this problem. The high cost of drilling additional monitoring wells, up until now represented one of the most important technological hurdles to overcome in order for passive seismic monitoring to move into the mainstream.

In 2000 Vetco Gray set out on an intensive R&D programme, the final objective being to design a low-noise tool designed for deployment in active wells. The revolutionary PS³ (Permanent Seismic Sensing System) is the result of this work.

Flow testing

At the product concept stage it became clear that little quantitative data had been published on the dynamic behaviour of seismic tools in flowing wells. Specific information was
required on the sources of acoustic noise and transmission paths within a flowing well. An absence of this information prompted Vetco Gray to include in its integrated R&D programme the aim of measuring and understanding noise generation and transmission processes within flowing oil wells.

The first challenge was how to make the requisite laboratory-type measurements within a flowing well environment. The solution was to construct a two-ended well section. Figure 2 shows the 15 m long inclined double-ended borehole that was drilled through the vertical face of a granite quarry, at Vetco Gray’s deep borehole test site in Cornwall, UK. The borehole is cased with 9 5/8 in (47 lb/ft) standard oilfield casing, and can therefore accommodate a variety of tubing sizes and elements of a typical well completion. The casing is cemented in place, and a string of three-component geophones is permanently cemented behind the casing so that they are well coupled to the casing and formation. Two 60,000 litre storage tanks allow fluid to flow through the borehole at rates of over 30,000 b/d (equivalent) using gravity drive to avoid contamination by pump noise.

Flow noise, both single phase and multi-phase, was monitored in different parts of the completion at flow rates between 5000 to 30,000 b/d. The data was then recorded using a 72-channel data acquisition system.

Numerical modelling and system investigations

The physical experimentation was run in parallel with numerical modelling and mechanical system investigations. An iterative process of experimental testing, numerical modelling together with comparison of predictions and observations resulted in a number of important insights into how best to reduce noise contamination in the wellbore environment. The principal insight concerned the importance of eliminating noise transmission paths from each acoustic source to each seismic receiver.

For this noise management part of the study Vetco Gray enlisted the help of world-leading flow acoustics experts from TNO in the Netherlands.

Scientific investigations were also conducted to determine the effects of different materials on the transmission of flow-generated noise within a completion. For example, the nature of the contact between the tubing and casing is an important parameter in the acoustic behaviour of the completion. As a result of various experiments, a special eccentriciser was also designed to optimise the performance of the whole system. The eccentricisers hold the tubing away from the casing and allow the system to be deployed into horizontal wells with no acoustic coupling between the tubing and the sensors.

Early experiments showed that noise levels inside casing and outside casing were very similar. However, noise levels on the production tubing were at least an order of magnitude larger at meaningful flow rates. The challenge was how to engineer a tool that could match the on-casing noise levels but that was conveyed to the required position using the tubing. The solution is in the PS3 system.

Tool development

Based on the in-depth knowledge gained from the experimentation, a permanent downhole seismic system was developed. The following requirements were seen as critical to the success of the system:

- Ability to monitor during production/injection operations i.e. low flow noise coupling
- High vector fidelity, i.e. resonance free across the seismic frequency range
- Acceptability to well engineers

The PS3 system represents a breakthrough in borehole seismic tool technology and opens up much wider opportunities.
for borehole seismic instrumentation and reservoir monitoring within the oil industry. With the seismic sensors acoustically de-coupled from the flow noise, and well coupled to the formation, the noise floor is dramatically reduced, allowing detection of much smaller and more distant seismic/microseismic signals.

The decoupling device is known as the Ω-Lok (Omega Lock), and is shown in Figure 3. It is held in a compressed state during the running in operation. Once the tubing string is in place, the release mechanism is activated by elevating the pressure in either the tubing or the annulus or via a hydraulic line. The Ω-Lok device is then released from the tubing, and pushes itself against the inside of the casing thus becoming extremely well coupled to the formation. The whole process is analogous to setting a packer except this device no longer touches the tubing. Figure 4 shows a schematic cross section of the Ω-Lok in its deployed state; note how the sensors are totally decoupled from the production tubing whilst being well coupled to the formation.

Figures 5 and 6 show for comparison purposes a constant seismic signal in different levels of noise caused by differing flow rates for the bow-spring (Figure 5) and the Ω-Lok (Figure 6). As the flow rate increases the signal from the bow-spring deployed geophones is soon lost in the increasing noise, whereas the Ω-Lok deployed systems still show good signal to noise.

The system is fully expandable. The operator can specify the number of levels and their positioning along the production string. Each level of the system utilises Vetco Gray’s patented 4-axis tetrahedral sensor configuration. This allows real-time QC of the data and provides a level of redundancy that cannot be achieved using the traditional three orthogonally mounted sensors. The system can be configured using geophones, MEMS accelerometers or fibre optic sensors. Other types of sensors (e.g. pressure and temperature) can also be incorporated if required. The system is rated to 300°F and 10,000 psi (150°C / 690 bar)

The step-change afforded by the PS® system enables continuous acquisition of both active and passive high quality seismic data in flowing wells for the life-of-field.

**Microseismic case studies and current status**

The background to the current surge of interest in microseismic technology derives largely from monitoring studies of geothermal systems (Baria et al., 1999). A comprehensive review of much of the work carried out in this field can be found in Niitsuma et al., 1999.

Early attempts to introduce this technology into the hydrocarbon world often suffered from equipment failure and a difficulty in obtaining sufficient support and understanding within client management. However a sufficient
number of important case studies did succeed in terms of demonstrating the potential of the technique.

In 1993 a production monitoring study was carried out in Clinton Co, Kentucky by the Los Alamos National Laboratory for Ohio Kentucky Oil Corp (Rutledge & Phillips, 1994). Over 3000 events were detected and locations from this dataset defined a shallowly dipping structure interpreted as a reverse-slip fracture zone, previously undetected from seismic reflection data (Figure 7).

During 1997 a passive seismic monitoring study of the Ekofisk reservoir was carried out for Phillips Petroleum. The data were acquired and processed by Vetco Gray (formerly CSMA). During this study 3000 microseismic events were recorded during only 19 days of monitoring. After further processing using the collapsing algorithm (Jones and Stewart, 1997), these location data were shown to map out a series of structures that parallel known fault trends within the reservoir (Maxwell et al., 1998). These structures had previously never been imaged because of an overlying gas cap (Figure 8).

Another monitoring project was carried out in the North Sea during 1998 in the Valhall field for BPAmoco (Dyer et al., 1999). This study used a similar configuration as the Ekofisk study and was also carried out by Vetco Gray (formerly CSMA). Over 500 microseismic events were detected and 324 located. Subsequent shear wave analysis of these data has demonstrated a temporal change in the shear wave anisotropy believed to be associated with reservoir drawdown (Teanby et al., 2004). Further analysis revealed how the microseismic data could be used to provide useful information for risk-based well and casing design that extended well life (Kristansen & Barkved, 2000).

By combining the microseismic data from Valhall and Ekofisk with in situ stress and pore pressure data, (Zoback & Zinke, 2002), it was shown how production induced normal faulting is believed to have spread out from the crest of the structures onto the flanks.

In addition to these reservoir monitoring studies, a number of injection monitoring studies were also carried out during the 1990s. Perhaps the most extensively analysed of these was the DoE/GTI funded Cotton Valley monitoring study of frac operations in an oilfield environment (Walker et al., 1997, Rutledge et al., 2003, Rutledge et al., 2004).

By the late 1990s a few of the major operators began to take a more long-term approach to the testing of this technology. Probably the most successful of these have been the Yibal study carried out for Shell/PDO by Vetco Gray in collaboration with PDO and SEPTAR (Jones et al., 2004) and the Peace River steam injection monitoring project carried out by Shell Canada (McGillivray, 2004).

The objective of the collaborative Yibal case study (Jones et al., 2004) was to demonstrate the value proposition for passive seismic monitoring by providing insight into reservoir behaviour upon which reservoir management decisions could be made. The following main observations and conclusions were drawn from this study:

- A high level of production related microseismic activity showed discrete spatial structures that vary in both intensity and size during the monitoring period.
- A working methodology has been successfully developed for relating reservoir induced microseismic activity to production/injection, and hence to the reservoir management process.
- The microseismic activity is associated with the two operational reservoirs (Natih and Shuaiba) and is strongly correlated with production/injection rates in the two reservoirs.
- A reservoir compartment has been successfully identified within the Natih gas reservoir using an integrated microseismic and geomechanical interpretation. The interpre-

![Figure 7](image1.png)  
**Figure 7** Shallowly dipping structure interpreted as a reverse-slip fracture zone from Clinton County study (Rutledge and Phillips, W. 1994).

![Figure 8](image2.png)  
**Figure 8** Collapsed event locations from the 1997 Ekofisk microseismic monitoring study
tation methodology adopted has also demonstrated the value of mechanistic geomechanical modelling in the understanding of reservoir processes related to production and compaction.

- A potential drilling hazard has also been identified for new wells around the edge of the compartment.
- Successful spatial and temporal monitoring of water movement has been achieved with two Shuaiba injector wells.
- The trial has provided a strong indication of how microseismic data can be integrated with 3D seismic reflection data and used in a quantitative manner to improve dynamic reservoir models.

The passive seismic monitoring of cyclic steam stimulation (CSS) carried out at Peace River by Shell Canada in association with SEPTAR, InputOutput and Engineering Seismic Group Canada produced the following conclusions:

- The existing model for conductive heating during CSS was shown to be false using microseismic data.
- Passive seismic monitoring can be used as a tool for determining how successful each CSS steam cycle has been in terms of creating new fractures.
- Microseismic locations are located along the edge of the heated zone.

Further analysis of the injection monitoring work carried out in the 1990s has illustrated a number of key monitoring issues and shown other insights into the processes by which frac operations stimulate the reservoir volume.

Perhaps one of the most important revelations deriving from passive seismic monitoring of frac operations concerns the disparity between theoretical models of hydrofrac geometry and frac geometries outlined by recorded microseismic locations. The models assume a symmetrical development whereas microseismic data show systematic asymmetry. More recent work (Rutledge et al., 2003 & 2004) has shed further light on the manner in which hydrofracs grow within the reservoir as the level of observed microseismic activity concentrates at bends or jogs in the fracture with minimal activity between these zones. Whether these ‘connection’ zones are observationally aseismic (i.e. the seismicity taking place is below the threshold of detection) or truly devoid of seismicity (i.e. a different failure mechanism is taking place) is an interesting avenue for further research.

The result of these case studies has been the establishment of passive seismic monitoring as one of the new reservoir sensing technologies suitable for inclusion into the digital oil field.

The future
The future for this technology appears promising. A number of case studies have demonstrated the potential of passive seismic monitoring. More recent work has demonstrated the value proposition for passive seisms through improved reservoir management. The acquisition and software technology is well developed and finally the downhole tool technology is available for monitoring in active wells (PS3).

A number of major national and international oil companies have either started or are planning to start passive seismic monitoring studies. Saudi Aramco is examining the possibilities of this technology for Ghawar (Dasgupta, 2004); BP has been testing downhole tool technology in Valhall (Barkved, 2002); Anadarko is using microseismic technology to map frac operations (Warpinski et al., 2004); TCO/ Chevron Texaco is carrying out feasibility studies on Tengiz (Raymer et al., 2004); Shell Canada has been carrying out CSS monitoring operations at Peace River (McGillivray, 2004); Exxon Mobil has been carrying out passive seismic monitoring operations of CSS at Cold Lake (Talebi et al., 1998); and Pemex has recently completed some pilot monitoring of frac operations (Kaiser et al., 2004).

The value proposition for passive seismic monitoring seems to be taking hold. When combined with conventional reflection and borehole seismology, the use of permanent downhole systems offers great potential for a better understanding and mapping of dynamic processes taking place in the reservoir. The next few years will see how well we are able to integrate 4D and microseismic information with geomechanical reservoir models and input these data into models describing pressure change and fluid flow in the reservoir.

Passive seismic monitoring consists of listening to a reservoir’s response to stress changes. The reservoirs we produce from have been talking to us for decades; now it would appear that the industry can start to listen.

References
(in order of reference within the paper)


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