The role of passive microseismic monitoring in the instrumented oil field

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With the current industry trend toward instrumented oil fields and smart well completions, the permanent deployment of geophones or other acoustic sensors to complement standard engineering gauges is being promoted as a way to map reservoir dynamics. The biggest push is from the time-lapse seismic practitioners, although the deployment of permanent seismic instrumentation is also potentially an ideal route to monitor passive seismicity.

Passive monitoring of acoustic emissions, or small magnitude microearthquakes (microseismicity) associated with stress changes in and around the reservoir, can also be used to image the reservoir dynamics. Passive monitoring has the benefit of more fully utilizing the seismic sensors to monitor during the periods between the conventional seismic surveys and offers complimentary information to both active time-lapse images and engineering measurements.

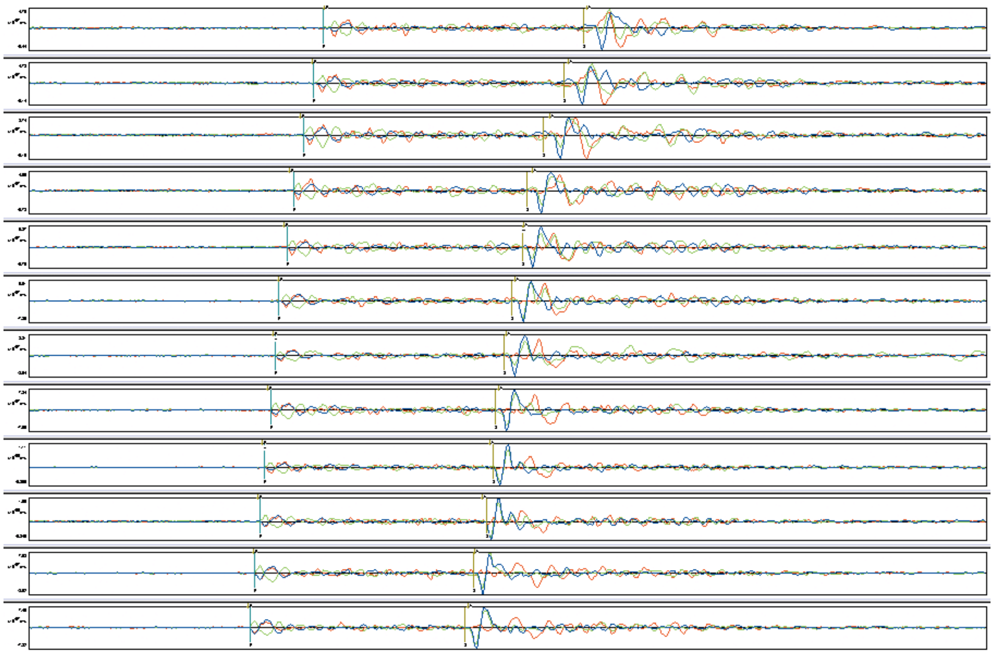

Figure 1. Seismogram of a microseismic event induced during hydraulic stimulation. Each trace is 0.3 s, with three components of a triaxial sonde superimposed in a different color. Signal was recorded on a 12-level wireline array (top trace is shallowest level).

Microseismic events, related to either induced movements on preexisting structures or the creation of new fractures, capture deformations as the rock mass reacts to stresses and strains associated with pressure changes in the reservoir. The microseismicity can be used to localize the fracturing or to deduce geomechanical details of the deformation. Since the Rangely experiment in the late 1960s, a number of passive seismic experiments have been pursued in the petroleum industry with varying degrees of success.

Recently, a number of independent operators have successfully implemented passive seismic studies to address specific issues. The majority of these studies are under the umbrella of hydraulic fracturing, where the microseismicity is used to directly map the fracture growth during well stimulations. However, a number of other studies have been used to image deformations associated with primary production, secondary recovery, or waste injection operations. In the vast majority of these cases, an array of seismic sensors are deployed by wireline to monitor for a specific period. This requires finding a well close to the action to facilitate detection of these small passive signals without impacting production.

Permanent sensor deployment in an instrumented oil field circumvents the chronic problem of well availability. In numerous fields, microseismicity is continually occurring and if the instrumentation were in place to properly record the data, additional information on the reservoir performance could be gained. As an aside, it is worth considering how much of the "noise" recorded in conventional seismics may be actually valuable microseismic data. The key will be to properly design the seismic arrays to cover both conventional active seismics (reflection, tomography, etc.) and specific issues associated with passive recording.

This article outlines a viewpoint of the potential applications and technical issues associated with passive seismic monitoring. Because passive seismic is probably best viewed as being in its infancy in the petroleum industry, it is worth standing back and considering applications in other industries where the technology is more mature. In mining, real-time microseismic data are used by supervisors to decide if it is safe to send miners underground. Microseismic data also are crucial in a number of other rock engineering applications, such as excavation stability in nuclear waste repositories, geotechnical stability, and performance of geothermal reservoirs. Permanent instrumentation in oil fields should allow the maturity of the technology to also help solve cer-

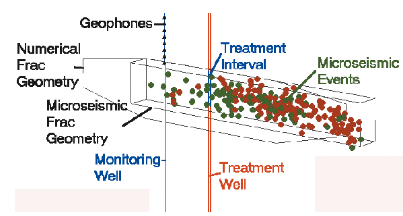

Figure 2. 3-D perspective view microseismic events induced during a hydraulic fracture (events color coded by concentration of sand in the injected fluid; green is low concentration, and red is high).

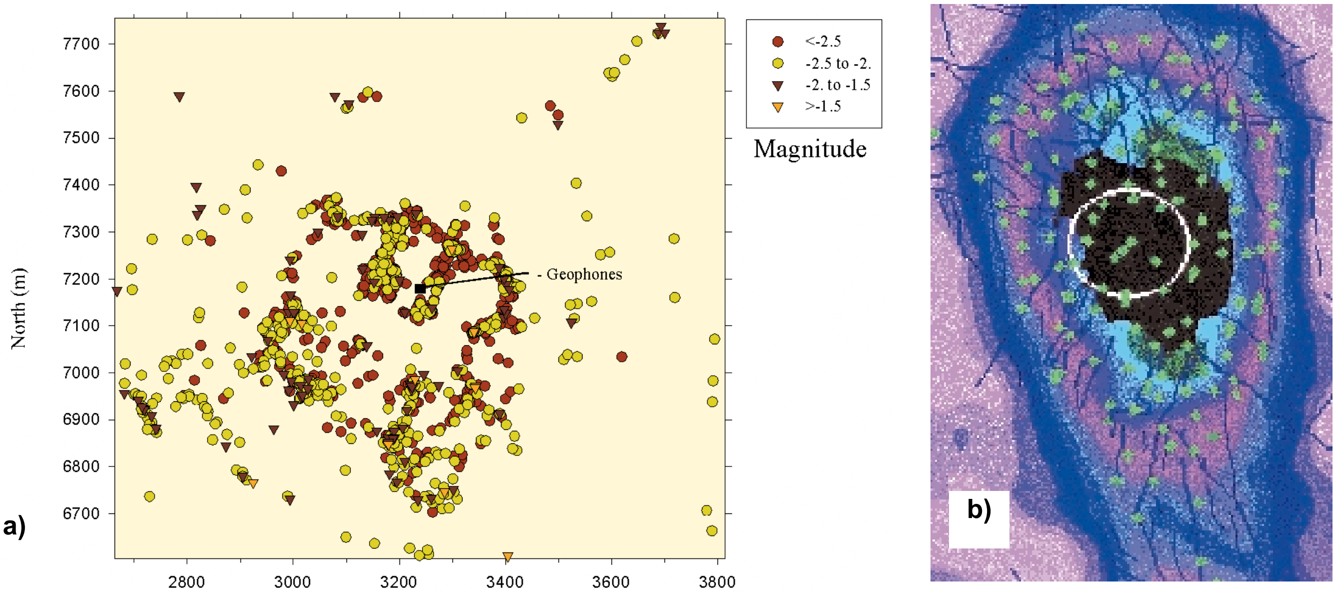

Figure 3. (a) Microseismicity recorded at Ekofisk with event locations scaled by magnitude. (b) Structural map of Ekofisk showing the gas cloud (black), major faults, and the region of microseismic detection (white circle). Note the preferred orientation of major faults in a NW-SE and NNE-SSW direction, which is similar to the orientation apparent from lineations of microseismic events.

tain geomechanical problems in the petroleum industry.

Here we will generally focus on borehole deployments, because passive monitoring will most likely involve borehole arrays to keep the instrumentation close to the action and maximize sensitivity. In some special cases, where induced seismic activity can be detected at surface, permanent surface arrays could be used in similar context to the picture painted below. However, for the most part, our discussion will focus on borehole arrays.

What is microseismic monitoring? Microseismic signals are generally recorded and processed in the same way as earthquake signals. First, continuous signals are analyzed with earthquake detection algorithms to determine when an impulsive energy source has occurred. The seismograms are then archived, including some pretrigger time window to capture the data prior to the detected signal. The seismogram of a microseismic signal is identical to that of a local, small earthquake with *P*- and *S*-wave phases (Figure 1). The relative amplitude of the *P*-and *S*-waves depend, however, on the deformation mechanisms and associated radiation pattern. Depending on the nature of the recording site, cultural noise can be an issue including tube waves when sensors are deployed in a borehole. Generally, true microseismic events can be identified based on the signal characteristics.

The basic processing of passive seismic data begins with locating the event (3-D hypocentral locations and origin time). In borehole applications, triaxial sensors are used to determine the raypath orientation of the incident phases. Detailed velocity models can be constructed from sonic logs, and the event location is calculated at the point in space that "matches" the observed arrival times of the different phases and raypath orientation. A database of event locations is then able to image the location of fracturing with time and has the advantage of automatic processing in real-time. Additional seismic attributes also can be determined from the amplitude and frequency content of the seismograms: such as the event magnitude, energy release, and by assuming some fracturing model the stress release, area, and displacement of slip. These additional attributes can be useful when interpreting the nature of the seismic deformation, and also can be automatically computed. A design study is usually required to optimize the number and location of sensors to maximize the accuracy of these calculated parameters.

Beyond these "standard" seismic attributes, the radiation pattern from the source also can be analyzed to determine the seismic moment tensor related to the changes in forces occurring at the source during the seismic deformation. The moment tensor can be interpreted in terms of the shear versus dilation or compressional nature of the deformation, or in other words whether the fracture is opening or closing which is a key factor in the fluid connectivity of the fracture. One constrained version of this analysis is to assume a shear deformation and apply standard earthquake fault plane (or "beach-ball") analysis. This can be used to determine the fault orientation and approximate principal stress directions. However, analyzing the radiation pattern requires an array of sensors surrounding the source. In most petroleum applications, the sensor distribution is not optimal to uniquely and accurately determine the deformation tensor. However, future instrumented oil field arrays may have a sufficient density of seismic sensors for this advanced analysis.

Microseismic data also can be used for local earthquake tomography, to image aspects of the travel path. This could potentially be in the form of either arrival-time tomography to image velocity variations, or full waveform inversion. Again, unless a sufficient density of permanent seismic sensors are deployed, the robustness of the analysis will be restricted with limited sensor array geometry. However, this aspect of the passive technology brings it closest to active seismics.

Potential applications. *Well stimulation.* During hydraulic fracturing, microseismicity can be used to image the orientation, height, length, complexity, and temporal growth of the induced fractures. For example, Figure 2 shows activity recorded during a stimulation, which can be used to directly measure the fracture dimensions and geometry. Time animation of the data also can be used to determine how the fractures grew in time. In this particular example, the fracture geometry is relatively simple with the growth of a single, dominant fracture plane, although in cases where fracturing intersects pre-existing fractures, the resulting fracture image can be relatively complex.

Seismic source parameter analysis (magnitude, energy, stress release, etc.) also can be used to qualitatively assess the variation in the seismic deformation, which can be used to infer the effectiveness of the fracture stimulation. Monitoring microseismicity in real time further allows for intervention during the stimulation, to increase the effectiveness by providing the on-site engineer with an updated image of the fracture growth. The images also can be used to calibrate numerical simulations of the fracturing and predict the probable drainage area when the well is brought on line. It is worth noting that commercial services are based solely on this one application.

Well/casing failure. Microseismicity can be used to monitor rock mass deformations that can cause well failure. For example, microseismic monitoring in the Valhall and Cold Lake Field identified microseismic activity in the overburden that were attributed to shear deformations causing well failures. In this case, the benefit is to identify regions of active deformation that would be susceptible to well failure, and monitor casing stability for operational safety.

Fault mapping. Movements of fault systems can be detected through microseismic monitoring. For example, microseismic recording over 18 days in the Ekofisk Field was able to identify the fault pattern under a gas cloud (Figure 3). The advantage of microseismic detection is that faults with small throws can be directly detected, whereas vertical faults are typically indirectly mapped with reflection seismology by offset horizons. The benefit is clear.

Mapping fluid movements/waterflood conformance. Pressure changes associated with fluid movements can be detected to track movements with time. For example, water inflow into a producing reservoir was detected by microseismic monitoring in Kentucky (Phillips et al., 1998). In the Ekofisk study, microseismic patterns may be related to waterflood effects (Figure 4). However, the specific mechanism at Ekofisk is probably enhanced by a water weakening mechanism, in that the injection of brine appears to be significantly weakening the chalk matrix accelerating the

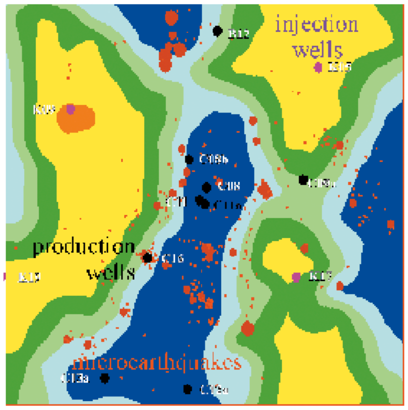

Figure 4. Contour map of water saturation (yellow is water flooded, blue is not flooded) and large magnitude microseismic events from Ekofisk. Note the lack of events in the flooded regions.

reservoir compaction. The benefit of the monitoring is to better calibrate and validate reservoir simulators. Microseismic monitoring could supplement time-lapse seismics in fields with a small impedance change.

Mapping compaction strains. Strains associated with reservoir compaction can be detected through microseismic monitoring, to investigate cap rock integrity. For example, the microseismic data recorded at Ekofisk was apparently related to reservoir compaction, as well as passive data recorded in the Lacq gas field (Grasso, 1992). The benefit of this application is the ability to verify geomechanical assessments of the compaction strains and monitor cap rock integrity.

Mapping thermal fronts. Thermal changes associated with steam injection also can potentially be tracked by microseismic monitoring, although this has yet to be clearly demonstrated with a petroleum case study. Microseismicity associated with fracturing induced by either thermal or pressure changes, could then be used to calibrate and validate simulations of the steam front dynamics.

Tracking fluid injection. Pressure changes associated with either fluid or gas injection can be imaged with passive data to improve reservoir engineering. In the Paris Basin in France, microseismic monitoring has been used to map gas movements in a gas storage reservoir (Deflandre et al., 1995).

Mapping waste disposal. Mapping fluid waste or cuttings injection can be tracked with microseismicity, to ensure that the waste injection is confined to target zones and confirm engineering design. For example, ARCO has done extensive work in this area for Alaska fields (Keck and Withers, 1994).

Given that the technology is mature in other fields and its many potential benefits, why isn't microseismic monitoring more commonplace in the petroleum industry? The reason can at least be partially attributed to technology; only recently have digital wireline arrays become available to record the small amplitude, high frequency data, with sufficient data quality to facilitate robust processing. Additionally most passive monitoring studies in the past have focused on the few fields where induced seismicity is felt on the surface. These fields are fortunately fairly rare. The successful downhole studies (i.e., Ekofisk), where the recorded seismicity was not strong enough to reach surface, relied upon recording a statistical population of events by placing the array close to the source (i.e., reservoir). For example, the maximum travel path for a recorded event at Ekofisk was 2 km, which means that for a reservoir at a depth of 3 km nothing would be detectable with a surface array. The other factor is the intrinsic seismic activity rate, which will depend on the strength of the rock and strain energy stored in the rock. Even cases with low activity rates can be overcome by longer term monitoring to build up a statistical population.

The availability of a well close to the action is often a factor against employing the technology, including the risk of shutting in a production well. Beyond the well availability is the costs of long-term deployment of wireline arrays, which are typically priced under a shorter term wireline business model.

The cost of the survey must be weighed against the potential benefit of the resulting data. With the limited number of field examples showing clear cost benefit analysis (such as hydraulic fracture imaging where the economics are well defined), it is necessary to educate the industry of the potential upside.

Interestingly, a well-designed permanent seismic array deployed when new wells are completed can help overcome most of these obstacles.

Token crystal ball section. At this point let's take a look at the potentially rosy future of passive monitoring in the instrumented oil field. Imagine a mature instrumented field that includes borehole arrays in numerous wells through a field, each at different stages. Massive volumes of passive data are probable, although the data management issues already have been addressed in other industrial microseismic solutions. The data will be automatically processed in real-time and the results available both in the field and back in the operator's offices through secure Internet lines.

To maximize the value of the array it will be preplanned to address as many of the potential applications as possible. The seismic instrumentation also will be fully integrated with both active seismic acquisition and engineering data. As an example, fully integrated microseismic, pressure, and temperature systems are commercially viable in the liquid petroleum gas storage world, covering everything from integrated acquisition through to visualization.

The array will first record the stimulation of the instrumented well, or at least immediately following the stimulation when noise levels from the frac have subsided. These data also will be supplemented with data from neighboring wells. The information can immediately be used by the engineers running the stimulation in the field, and for post mortem analysis of the stimulation and well performance.

As the well is brought into operation, detection sensitivity will be compromised with increased background acoustic noise levels associated with fluid flow in the well. However, during periods where production is stopped, the associated noise levels will fall and the sensitivity of the array enhanced. The stoppage may be due to regular maintenance or purposely stopped for a critical period of recording. Induced fracturing due to pressure changes associated with production will provide insight into drainage areas and help characterize fracture networks and compartmentalization.

During secondary recovery microseismic monitoring will be used to track fluid movements in the reservoir, and help to fill in between the intervals of the conventional time-lapse recordings. Integrated active and passive images of the reservoir dynamics can then be used to improve reservoir simulations.

A secondary potential application is with specific geomechanics issues that arise during the reservoir life cycle. Passive seismic monitoring can directly monitor deformation, either for faults or fractures that cut through the reservoir and directly impact the fluid pathways, or indirect faulting/fracturing around the reservoir. Furthermore, with a permanently instrumented oil field, the historical baseline behavior of the seismic fracturing can be used to assess how the current deformation has developed. As an example, if questions arise in a mature field development around a fault sealing problem, historical passive data can be used to first locate the fault and also to assess if the deformation characteristics have changed with time.

Technical issues. As with any oil field instrumentation, there are a number of obvious expectations, such as being transparent to the well completion and production, cost effective, robust, and properly engineered to provide the necessary data. There also are specific technical issues associated with passive seismic monitoring, i.e., noise, coupling, sensor arrays, and continuous recording.

Instrumentation of an active well will likely involve increased acoustic noise levels associated with fluid flow within the well. The nature of this noise will probably be site dependent, and could potentially restrict the passive monitoring capabilities. It is possible to design the instrumentation to suppress the noise, depending on the characteristics.

The seismic sensors need to be in mechanical contact to the formation, so that the true ground motion can be recorded. There are two related factors: how the sensors are mechanically installed in the well completion, and equally how the well completion is installed in the formation. Mechanical resonances of the various components also could be an issue at the microseismic frequencies.

The location and number of sensors required for passive monitoring will not necessarily be the same as for conventional seismics, and so it is necessary in the preplanning stages to optimize the array for both potential applications. Also passive monitoring may require sensors in the reservoir, and so unlike permanent VSP arrays may require some re-engineering of the well completion (such as passing lines through packers). However, clearly the impact on the drilling and completion engineer must be minimized, and will be as the implementation of the technology matures.

Unlike active seismics where only shot records are needed, passive seismic requires continuous recording for the event detection algorithms. Furthermore, the passive signals tend to be lower amplitude and higher frequency (amplitudes less than a micron/s and frequencies up to 1000s Hz for microseismic applications) compared to active seismic. Unfortunately, with passive seismic we don't have the luxury of signal averaging or stacking the signals to improve signal-to-noise. In order to get the desired passive data quality, sensitive, low-noise instrumentation is needed.

Token road map section. To summarize, passive seismic has great potential and most of the apparent reasons why the technology is not more routinely employed (such as availability of a monitoring well for wireline monitoring) can be solved with a permanently instrumented oil field. Nevertheless, more definitive case studies are required showing the benefit of the technology. In the past, passive monitoring examples have often been driven by operators with specific problems, at least those who are open to new technology or have exhausted other technological solutions. Seismic instrumented oil fields should open up new potential applications for passive monitoring, whether it be on its own regard or as added value for an active application. With more case studies showing how the technology can be used in reservoir characterization applications, the technology will become more commonplace.

Suggested reading. "Mechanics of seismic instabilities induced by the recovery of hydrocarbons" by Grasso (*Pure and Applied Geophysics*, 1992). "Using microseismicity to map Cotton Valley hydraulic fractures" by Urbancic and Rutledge (SEG Annual Meeting, 2000). "Real-time microseismic mapping of hydraulic fractures in Carthage, Texas" by Maxwell et al. (SEG Annual Meeting, 2000). "Microseismic logging of the Ekofisk reservoir" by Maxwell et al. (SPE 47276). "Use of passive seismic monitoring in well and casing design in the compacting and subsiding Valhall Field, North Sea" by Kristiansen et al. (SPE 65134). "A field demonstration of hydraulic fracturing for solids waste injection with real-time passive seismic monitoring" by Keck and Withers (SPE 28495). "Reservoir characterization using oil-production induced microseismicity, Clinton County, Kentucky" by Rutledge et al. (*Tectonophysics*, 1998). "Microseismic surveying and repeated VSPs for monitoring an underground gas storage reservoir using permanent geophones" by Deflandre et al. (*First Break*, 1995).

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