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SEISMIC TECHNIQUES IN GEOTHERMAL AREAS

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SUMMARY - In the petroleum industry, seismic reflection is ***the*** exploration tool. The question is "Why is seismic reflection not used in geothermal areas?". Seismic techniques work in complex geology (volcanic, and severely folded and faulted sediments), they also work in gas dominated areas. Considering seismic techniques as ***development tools***, bring the costs into an acceptable budget (a 3D survey cost as little as 2 wells). Basic well seismic techniques (Well Seismic Profiles, Cross-hole tomography) are cheaper viable options depending on the answers being sought.

1. INTRODUCTION

In 1979, Applegate & Donaldson concluded that; "Seismic techniques clearly deserve more application and research for geothermal studies". After 17 years we re-iterate their conclusion, particularly considering the development of seismic technology in this time.

Seismic reflection is ***the*** exploration tool in the petroleum industry. It is instmmental in providing interpreters with the data to delineate a hydrocarbon trap. Considering its value to the petroleum industry, we ask "Why is seismic reflection not used in geothermal areas?". The current consensus of opinion was that the geothermal industry holds that seismic reflection; does not work in complex geology; does not work in vapour dominated fields; and is basically too expensive.

Seismic techniques have been used on some geothermal fields, most notably Larderello-Travale in Italy, and The Geysers in the USA. Data has also been acquired in New Zealand, Mexico, and Japan.

The objectives of this paper are three-fold:
- to summarise the seismic techniques available to the geothermal industry.
- to present surface seismic as a development tool to be applied during the production drilling and reservoir management stages.
- to highlight the value of well seismic techniques.

2. SEISMIC TECHNIQUES

Many books describe the basic theory behind seismic reflection techniques (for example; Telford et al, 1976 and Dobrin & Savit, 1988). We review seismic techniques with respect to their potential in geothermal.

2.1 Surface Seismic - Seismic Refraction

Seismic refraction is the basic approach taking a simplistic geological view of the sub-surface. This technique is concerned with the seismic waves that travel along an interface between two 'different' rock types. Refraction data can be used to correct for near surface velocity variations in seismic reflection surveys.

2.2 Surface Seismic - Seismic Reflection

Seismic reflection is the most used application, working with reflected waves. The whole range of seismic technology is continually improving. Major advances with surface seismic occurred when three dimensional (30) blocks of data were acquired and processed.

The Larderello geothermal field (Italy) has been the focus of many seismic techniques, 2D and 3D surface, and multi-offset WSP (section 2.5). Significantly, a 3D survey covered the field to image geothermal reservoirs within the metamorphic basement. Batini et al (1990) found the 3D data to be vastly superior to previous 2D data. Rather than dealing with uncertain interpolation between 2D lines, the interpreter used 'rugged' surface maps. Batini et al (1990) reported that productive wells drilled on the basis of this work confirmed a correlation between production and anomalous amplitudes.

2D data has been used in geothermal areas in New Zealand. Henrys & Hochstein (1990), reviewed a 1984 study, with other geophysical data, to map subsurface volcanic structures in an active hot water system. They found that a layer's average interval velocity decreases by 10 to 15 % inside the field. Although seismic data gave a better correlation of the volcanic stratigraphy, Henrys & Hochstein noted the poor quality of this data relative to that of thermal fields in sedimentary rocks. In general, the results demonstrate the importance of reviewing all data at the post drilling phase.

At Snake River plain (Idaho, USA), volcanics. cover metasediments. Young & Lucas (1988) used a suite of geophysical techniques to 'see' below the volcanics. Seismic alone could not determine the underlying sediment stmcture, but with a combination of gravity, MT, seismic reflection and refraction, greater confidence was given to the final interpretation.

Morse et al (1987) used a variety of seismic processing techniques on data from a structurally complex area. Short arrays and high fold acquisition significantly improved data quality, and aided in imaging steep dips. 2D structural modelling consisted of matching a synthetic time response to the real data. Although proper migration was not achieved, the techniques used were considered successful.

La Bella et al (1996) reported a successful 3D seismic survey carried out in both mountainous terrain and complex geology (the Appennines, Italy). The objective was to locate the main fracture trends. Previous 2D seismic gave very poor data due to a highly variable spatial seismic response. The project used a 'global planning' approach to plan the survey.

3D seismic data were used to determine the growth history of faults in areas of complex geology. Chapman & Meneilly (1990) describes the use of 3D data to map faults, and then to use sequential restoration to determine the history of the growth of a selected fault.

2.3 Shear Waves (S-wave)

The effect of gas on seismic reflection data has been known for some time (Andreassen et al 1990, Ensley 1985, Neidell 1985, and Mastoris 1990). Seismic energy is attenuated when it travels through gaseous zones (i.e. steam/gas in a geothermal field). Gas within a formation shows up as a low velocity layer above an anomalously high amplitude reflector. This cuts through dipping layers and is known as a "Bright Spot" (Neidell, 1985).

Unlike P (compression) waves, changes in fluid content of the rock do not significantly affect S (shear) waves. Therefore gas (steam) related P-wave "bright spots" have no comparable S-wave anomaly. Ensley (1985) and Neidell (1985) show the importance of S-wave data to determine if a bright spot is due to gas, or lithology (seen in both P-, and S-wave sections).

Mastoris (1990) warns of the effects of gas distorting the underlying seismic data (velocity pull-down). Processing, through the integration of well velocities with seismic stacking velocities, creating an accurate 3D velocity model, can correct for this effect.

Davy (1992) shows the effect of gas on New Zealand seismic data. A survey on Lake Rotorua showed a strong lake floor reflector (gas saturated sediments) masking all underlying reflectors. The shallow gas horizon (a 180 degree phase shift high-amplitude reflector), gives rise to strong (constant phase) multiples. Velocity pull-down affects the seismic data below this reflector. An area of seismic "whiteout" with few apparent reflectors is due to scattering from gas bubbles within the formation. Discrete gas horizons appear as bright spots. Pockmarks seen in the lake floor reflector are ascribed to gas leakage into the water column. Strong constant phase multiples underlie the pockmarks.

Lamarchie (1992) found that geothermal conditions (gas, steam pockets, and warm highly altered rocks) severely attenuated the high frequency signal. There is a change in seismic character as a seismic line passed into an area of surface thermal features (Whakarewarewa, New Zealand). Signal quality vaned with intensity of geothermal activity, ground temperature, and where geothermal fluids were indicated by resistivity methods,

Ampiitude Versus Offset (AVO) is a method of extracting S-wave information from P-wave data. At an interface, seismic energy produces both P- and S-waves. Depending on the acoustic impedance contrasts at an interface, the ratio of generated P-waves to S-waves will change. The seismic trace amplitude increases with the production of more S-waves. AVO can determine where the acoustic impedance is changing, giving an estimate of Poisson's ratio, and an indication of the material's saturation. Miles (1988) noted that there was no sure way to correlate P-wave and S-wave data. But, with 3-component data, AVO inversion of the P-wave gather predicts the S-wave time velocity and amplitude changes with offset and vice versa.

S-waves are slower than P-waves, giving higher resolution when plotted at the same "vertical" scale as P-wave data. S-waves are about 10 times more sensitive to near-surface effects, so it is important to get surface corrections (statics) right. With a 3-component dataset, the P-wave data are processed first, and the P-wave statics are used to fine tune the S-wave statics.

2.4 Shear Wave Splitting (Birefringence)

S-waves are sensitive to the intemal structure of the rock, such as changes in crack and pore geometry caused by changes in pore pressure, or pore fluid properties, or stress. S-wave data can be used to determine bulk material properties.

An area of seismic anisotropy has little effect on P-waves, but S-waves are much more susceptible. On entering a region of seismic anisotropy, S-waves are split into two or more phases with differing velocities, and different polarisations (Crampin 1984). Changes in S-wave splitting behaviour have been seen before and after earthquakes, and before and after pumping into a hot dry rock geothermal reservoir (Crampin 1990).

Martin & Davis (1987) used S-wave splitting to detect fractures and their orientation. The best cumulative production in the Silo oil field (USA) came from wells with a high density of NW-SE fractures (seen in existing well logs). Azimuthal anisotropy was calculated from S-wave data, giving information about the location, orientation and intensity of subsurface fractures. Positive values of azimuthal anisotropy indicated NW-SE orientated fracture alignment, agreeing with the well data.

2.5 Well Seismic Profile (WSP)

Well Seismic Profiles (WSP) investigate the area close to the wellpath. As this technique was developed on vertical wells, WSPs are more popularly known as VSPs (Vertical Seismic Profiles). WSP data have higher resolution than surface seismic due to the shorter wave paths. The original use of WSPs was to integrate well data (geophysical and geological logs) with seismic data.

Majer et al (1988) used WSP at the Geysers, USA for fracture detection. High resolution surface seismic data was shot for comparison. WSP data was processed to estimate bulk properties from velocity anisotropy. Fractures were inferred from bulk material properties because fracture spacings are of the order of a few metres, compared to the seismic wavelength of 100s of metres. They found cross-polarised S-wave anisotropy, but not P-wave anisotropy. Poisson's ratio decreased as the production zone was approached due to increasing dry steam fraction in the pore spaces of the rocks. They concluded that the anisotropy came from dominant fractures above the steam zone. Majer et al emphasised the potential of 3 component multi-offset VSP data to determine fracture content and orientation.

Several WSPs have been acquired in Larderello (Italy) (Batini et al., 1985, Cameli et al., 1995, Gibson et al., 1995). The WSPs were interpreted in conjunction with other seismic techniques (2D, and 3D seismic).

Working on a WSP in a complex alpine overthrust area, Winkler & Cassell (1989) found that 3-component acquisition improved the signal to noise ratio, allowed the separation of P, and P-S converted wavefields. Good correlation was found between WSP and dipmeter results, and with surface seismic, although this latter dataset was poor.

2.6 Seismic (Cross-hole) Tomography

Seismic tomography investigates seismic waves created in one well, and received in a second (or more) wells. There can be many solutions for one tomographic dataset. Generally, seismic tomography is used in conjunction with other seismic techniques. Nakagome et al (1995) used seismic tomography, WSP, surface seismic, and pressure transient data to investigate a fractured reservoir (Hohi field, Japan).

Fehler & Pearson (1984) located large fractures by detecting changes in signal amplitude, waveform, and frequency content. At a hot dry rock geothermal site, a man-made hydro-fracture system acted as a downhole heat exchanger between two wells. P- and S-wave amplitudes are related to the source-receiver distance and dip of the raypath. From travel time and amplitude information, a Q (Seismic Quality) factor was calculated and plotted. Fractures are "seen" through shadow zones where signal amplitude suddenly decreases. By pressurising the reservoir, the shadows become more pronounced. Comparing amplitudes gives an estimate on the number and size of fractures.

2.7 Microseismic

Geothermal areas can be investigated using natural "micro-earthquakes" as the source. This data can be used to deduce information of the velocity structure between the source and the geophone. As the exact origin and time of the micro-earthquake is not known, resolution is low. Using man-made seismic sources improves resolution. Fluid injection into the formation around a well can also be used as the trigger. Micro-earthquakes associated with geothermal areas can be due to tectonic stress, associated with geothermal fluid increasing the pore pressure, and by bubble collapse (Tosha et al., 1994).

Micro-earthquakes are investigated to locate their origin. Hochstein et al (1995) investigated earthquake swarms near Lake Taupo (New Zealand). The earthquake swarms followed the alignment of basement fractures. The swarms were interpreted as magma injections into these fractures from deeper chambers (dyke injection).

2.8 4D Seismic

4D seismic is a generic term referring to repeated seismic studies of an area. King (1996a & b) describes 4D seismic as time-lapse 3D to follow the fluid distribution within reservoirs. Since the mid-80's, 3D along with well logs, core, petrophysical, and production characteristics were combined to present a picture of the reservoir characteristics. Seismic differencing techniques monitor reservoir fluid changes over time.

3. DISCUSSION

The objective of basic seismic techniques is to image sub-surface geology, horizons, faults and fractures. S-wave techniques allow the identification of gas effects, and the determination of bulk material properties.

Seismic techniques score over traditional geothermal exploration methods by having a higher resolution. In geothermal, seismic methods can be used to map competent formations that can hold or direct the flow of geothermal fluids. The location, orientation, and intensity of fractures can be detected. Seismic can 'see' through conductive layers that are opaque to resistivity methods.

On reading the cited publications it is noteworthy that different seismic techniques were used together. Some reported seismic in conjunction with other geophysical techniques (MT, gravity etc), one (Nakagome et al, 1995) used pressure transient data. The use of WSP is widespread. A lot of effort goes into planning surveys, particularly in complex geology, and mountainous terrain.

3.1 Seismic reflection **can work** in complex geology.

The full range of seismic techniques have been used successfully in areas of complex geology, both in volcanic areas, and in severely folded and faulted sedimentary areas. The best way to seismically image complex geology is through a 3D survey. Migration techniques can collapse the data to its correct sub-surface position. Work with sequential restoration of fault movements opens up the possibility of reconstructing the volcanic history of a geothermal area.

3.2 Seismic reflection **can work** in vapour dominated fields.

The effect of gas on conventional P-wave seismic reflection data is well known. The use of S-wave data and processing techniques can combat the effects of gas, and are also used for fracture detection.

3.3 Seismic reflection is expensive.

To resolve complex geology, 3D surface seismic data should be collected. Further, 3-component data should be acquired if the field may contain gas/steam, or for fracture detection and orientation. Such a survey allows you to position subsequent wells confidently.

3 0 Acauisition and Processinq Costs - The cost of a seismic survey is very site specific, depending on terrain, the weathered layer, geological complexity, climate, and environmental concerns. Careful planning before starting acquisition is very important to reduce costs, and optimise the ensuing processing. As an example, below we estimate the cost of a 3-component 3 0 seismic survey for a geothermal field in New Zealand. A feature of the Taupo Volcanic Zone is that deep (10+ m) shot holes are needed to make sure that the seismic source is beneath the worst of the weathered layer.

This hypothetical field covers 13 km^2, but to account for edge effects at the migration processing stage, the required acquisition coverage is 36 km^2. The assumed acquisition parameters are 15 fold in CMP bins $12.5m^2$ (96,000 traces per km^2). The total cost (acquisition plus processing) is around US **$2** million ($55,555 per km^2). Acquisition is about US $1.35 million ($37,500 per km^2). Roughly one third (US $475,000) is taken up with shot hole drilling. A further third covers data acquisition. The final third covers expenses (permits, surveying etc). Acquiring 3-component data is an extra US $14,000.

Processing for this hypothetical 3 0 survey is in the order of US $500,000. Conventional P-wave processing costs US $200,000 - $275,000, and a further US $135,000 for each processed shear field. The lower S-wave processing cost takes advantage of the previous P-wave processing (i.e. statics). Modelling and interpretation will use a further US $70,000.

Bee et al (1994) describes techniques used to acquire 3D seismic in a jungle environment (Sumatra, Indonesia). Proper planning maximised the seismic coverage, whilst decreasing the amount of jungle cutting. GPS (Global Positioning System) increased surveying productivity by up to 50 % compared to old surveying techniques. Radio shooting (rather than wireline shooting) also increased productivity. Constructing a high radio tower in the middle of the survey area helped radio coverage.

The cost of 3 0 acquisition vaned from US $9,000 to $78,000 per km^2. This depends on data density, Bee at al (1994) normalised these figures. For a data density of 33,333 traces per km^2 (equivalent to 20 fold in a 15m x 40m CMP bin), a 3D survey costs between US $20,000 and $40,000 per km^2. Bee et al reported an average for their work of around US $20,000 per km^2 in 1992.

To review our example, the acquisition cost is US $37,500 per km^2, which normalised to a data density of 33,333 traces per km^2 is US $13,000 per km^2.

Fundinq - It takes a brave company to change its spending on exploration methods from $100,000 to $3,000,000 in the eariy stages of a project with no income. One way is to view a 3D seismic survey as a development tool, a second is to defer the initial outlay.

We feel that in geothermal areas surface seismic are seen purely as very expensive 'exploration' tools. We therefore argue that surface seismic techniques be viewed as a development tool. Development budgets far exceed exploration budgets, and can therefore absorb the expense of surface seismic.

The costs of wells vary from site to site. Grant (1996) surveyed recent literature and found that the average cost of a geothermal well is US $1.5 million. This figure includes the costs of reinjection wells & failures, a combined figure that varies from 25% to 41%. Therefore the cost of our hypothetical 3D seismic survey is roughly equal to 1 or 2 wells. In a large field the benefits of better placed wells will be felt financially.

A 3D seismic survey can be acquired, possessed, and interpreted speculatively by a third party. The resulting geological model is leased to the geothermal developer. The developer gets the information, with expenditure spread over the field's production life. For instance, instead *of* spending US **$2** million in one go, for a ten year lease the developer could spend $300,000 per year.

3.4 Seismic, geothermal, and the future

Surface seismic (particulariy 3D) are expensive. Viewing the technique as a development tool brings the costs into focus, and into an acceptable budget. By saving the cost of poor well locations the cost of the 3D survey can be recouped.

Basic well techniques (WSP, Tomography) are much cheaper and are viable options if the well is in the right place, and you are confident of getting the information you require. However, 3D WSP acquisition can cost up to ten times that of an equivalent sized surface 3D. An advantage with 3D seismic, is the opportunity to acquire WSP data with little additional cost. Thus coupling surface seismic with downhole data.

A great deal of petroleum industry money has developed and refined seismic techniques over many decades. These techniques have improved to the point where they have solutions to problems posed by geothermal developments. The petroleum industry is cost conscious and the supply of seismic technology is a competitive market. The geothermal industry has the opportunity to reap the benefits of years of this expensive research.

Seismic data will last the lifetime of a geothermal field, during which, continued improvements in processing and interpretation can be used. In the case of 4D seismic, an initial dataset compared with a second dataset, may give information on reservoir depletion.

Despite the continued advances in seismic technology, geothermal still pose problems that require further investigation. Surface waves can interfere with S-wave data. 3-component geophones with polarised filters go some way to resolving this problem. Chaotic (rather than complex) geology can affect the seismic data if the acoustic impedance contrasts within the formation are strong. This may not be a problem if the target is a vapour zone, or the chaotic formations are limited in extent. Well data helps to alleviate this problem. Acquiring well data in high formation temperatures is tricky. This problem is constantly being addressed, for example, Nakagome (1995) reported the development of a new high temperature (260 °C) receiver.

In the geothermal industry, reservoir determination depends on a multi-disciplinary approach. The integration of a wide range of techniques (geochemistry, geology, geophysics) indicates the extent of a geothermal reservoir. Seismic reflection cannot replace this extensive suite of geothermal exploration techniques, nor do we advocate this. We view any seismic technique as a high resolution supplement.

With the advent of 4D seismic, geologic and engineering software tools have to be compatible (King,. 1996a & b). Models common to all disciplines have to be used. The need for interdisciplinary decisions and analyses requires a truly integrated project team. We note that an effective integrated geothermal team would select the appropriate method (seismic or otherwise) to answer the geothermal question being posed.

Modelling three dimensional geothermal reservoirs, has to be done three dimensionally. An interpreted 3D seismic survey will give the structural data with which all geothermal data (exploration and production) can be integrated. This requires all other types of data (geochemistry, geology, gravity, MT, and production) to be accessible, easily done if held in a comprehensive geothermal database such as "GDManager" (Anderson, Clark & Ussher, 1995).

4. CONCLUSIONS

- Seismic techniques can work in complex geology.
- Gas and steam do not seriously affect some seismic techniques (S-wave).
- S-wave techniques give additional information on bulk material properties.
- The best technique to use is 3-component 3D seismic reflection. Geology and reservoir parameters can be extracted from this 'solid' block of data.
- Well seismic gives valuable formation information around the wellpath.
- Well seismic combined with other seismic techniques enhance the value of both.
- 3D seismic surveys are not prohibitively expensive in terms of some geothermal development budgets.
- There are options to fund a 3D seismic survey:
    1. View it as a development tool.
    2. Involve a third party to speculatively acquire, process, and interpret the survey, then lease the data/model back over a long-term period.
- Performing a good seismic study in a geothermal area will require very careful planning.
- Seismic techniques clearly deserve more application and research for geothermal studies.

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