Considerations of observed spectral anomalies over hydrocarbon reservoirs generated by microtremors

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Abstract

Narrow-band, low-frequency (1.5-4 Hz) tremor signals on the surface over hydrocarbon reservoirs (oil, gas and water multiphase fluid systems in porous media) has been observed worldwide. These 'hydrocarbon tremors' possess remarkably similar spectral and signal structure characteristics, pointing to a common source mechanism, even though the depth (some hundreds to several thousands of meters), specific fluid content (oil, gas, gas condensate of different compositions and combinations) and reservoir rock type (such as sandstone, carbonates, etc.) for each of those sites are quite different. However, the physical mechanisms underlying these observations are presently not fully understood. We propose a scientific strategy for better understanding those phenomena. Using well-known rock physical relationships we have identified on macro-, meso- and microscale different mechanisms which can induce anomalies in the low-frequency band. Using different numerical approaches we are able to compare these mechanisms with observations in the field.

Introduction

During several surveys at different oil and gas field locations throughout the world (so far more than twenty), the presence of 'hydrocarbon tremors' was observed and a high degree of correlation to the location and geometry of hydrocarbon reservoirs could be established (Dangel et al., 2003; Holzner et al., 2005; Graf et al., 2007 and references therein). These tremors provide a direct hydrocarbon indicator for the optimization of borehole placement during exploration, appraisal and production. In addition, there is a strong correlation between the tremor power and the total hydrocarbon-bearing layer thickness (THLT) determined by borehole logs. The ever-present seismic background noise of the earth (e.g., Berger et al., 2004) acts as the driving force for the generation of hydrocarbon indicating signals. In contrast to conventional 2D and 3D seismic technologies, the investigation of 'hydrocarbon tremors' is entirely passive and does not require artificial seismic excitation sources. The modification of the seismic background noise spectrum is different for interactions with geological structures containing hydrocarbon filled pores compared to interactions with similar structures not containing hydrocarbons (Figure 1). Therefore, the hydrocarbon microtremor analysis is in line with an increasing number of methods which investigate ambient noise signals to get information of the subsurface structure (e.g.; Bard, 1999).

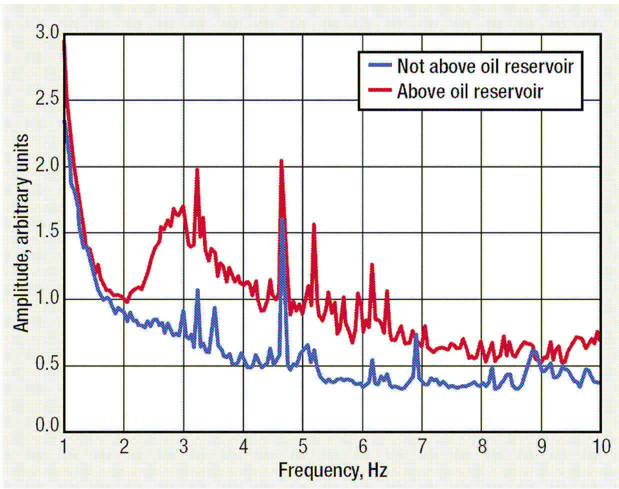

Figure 1: *Data from a survey in Brazil showing consistent anomalies in the Fourier spectra of surface velocities, measured within and outside the boundaries of a known oil reservoir. The highest difference is mostly observed in the range between 1.5Hz and 4Hz.*

As reported above, the characteristic spectral anomalies caused by hydrocarbon bearing structures have been consistently measured during several field studies but the physical mechanisms causing these anomalies are not yet fully understood. In this paper we discuss different possible physical mechanisms on macro-, meso- and microscale, which can generate low-frequency spectral anomalies of a broadband incoming background signal (i.e. ambient seismic noise). The qualitative and quantitative influence of those mechanisms is investigated by numerical modeling tools and compared to a large variety of available field measurements.

Numerical tools

One main methodology to study the influence of possible low-frequency mechanisms is numerical modeling of wave propagation in porous rocks. We use the velocity-stress and displacement-stress formulations of the governing equations and solve these equations numerically using an explicit finite difference method on a standard or rotated staggered grid (e.g., Virieux, 1986; Saenger et al., 2000). We solve equations describing an elastic medium, a poroelastic medium (Biot, 1962) and a poroelastic medium with partial saturation (Carcione et al., 2004). Numerical simulations are performed for 1D, 2D and 3D. A particular aim is to study under what conditions simpler 1D and 2D models provide similar characteristic spectral anomalies than full 3D models. In a later stage the numerical models will be implemented into a new hydrocarbon detection method. The idea is to fit observed spectral anomalies with numerically produced spectral anomalies by optimizing/minimizing the misfit between real and synthetic spectra. The continuously improved physical understanding will be used to design suitable update mechanisms that vary the material properties and the geometry of the reservoir to provide probabilities for the location, thickness and type (oil or gas) of the reservoirs.

Rock physical mechanisms in the sub-10Hz domain

Possible low-frequency mechanisms are (i) standing wave resonance (macroscale), (ii) selective attenuation (mesoscale) and (iii) resonant amplification (microscale). They are illustrated in Figure 2. Even if one or more of these mechanisms are not responsible for the characteristic hydrocarbon tremor signals, we need to quantify these effects anyway to clean the measured data from spectral anomalies which have not been generated by the hydrocarbon bearing geological structures.

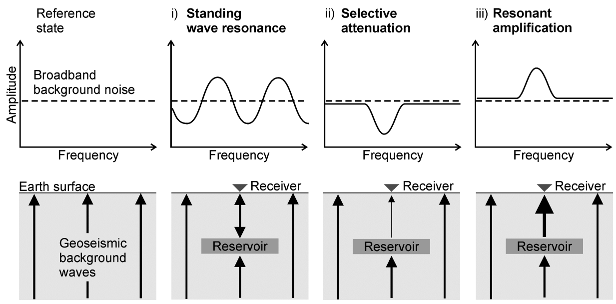

Figure 2: *Three possible mechanisms that generate characteristic modifications of the geoseismic background spectrum. The Reference state exhibits no heterogeneities in the subsurface and an incoming broadband ambient noise. i) Characteristic maxima in the spectrum are generated due to reflections between the reservoir and the surface and within the reservoir caused by smaller impedance within the reservoir. ii) Characteristic peaks in the microtremor spectra are generated due to selective, i.e. frequency dependent, attenuation within the reservoir. iii) Characteristic peaks are generated due to a resonant amplification of certain frequencies within the reservoir.*

(i) Standing wave resonance

When waves propagate from one medium into another medium with different material properties, then a part of the wave is reflected. The characteristic two-way travel time or resonance frequency between the Earth surface and the bottom of the surface layer or the reservoir generates characteristic spectral anomalies. Importantly, the effective impedance contrast can be enhanced significanly by high attenuation in the low-frequency range in reservoir rocks (Korneev et al., 2004, Chapman et al., 2006). We study spectral anomalies generated by standing wave resonance for elastic and poroelastic media. For poroelastic media, we compare results obtained with the Biot model and the models of the theory of porous media (TPM, e.g., Ehlers and Kubik, 1994). The motivation to study wave propagation also with the TPM equations is that the TPM is a priori a nonlinear approach in contrast to Biot's theory, which is purely linear. Another focus is to study the effects of several reservoirs which are located at different depths and to develop a methodology which allows for estimating the number of reservoirs in depth.

(ii) Selective attenuation

There exist several models to describe the attenuation of seismic waves due to wave-induced flow (e.g., Pride et al., 2004). These models describe wave attenuation on different spatial and temporal scales. A model which describes presumably the dominant mechanism in the low frequency range between 1 and 10 Hz is the so called patchy saturation model (White et al., 1975; Gurevich and Lopatnikov, 1995; Johnson, 2001). We study patchy saturation effects within the reservoir to determine under what conditions a selective, frequency dependent attenuation could generate spectral anomalies similar to the observed hydrocarbon microtremor signal. The results for wave attenuation on the reservoir scale will be approximated by an effective viscoelastic model to simulate wave propagation on the upper crustal scale (top 10 kilometers). In particular, we study the differences between gas and oil pore fill and the consequences on the frequency dependence of the reflection coefficient.

(iii) Resonant amplification

Resonant amplification effects of the ambient seismic noise are promising candidates for explaining the hydrocarbon microtremor signal. These effects will behave like a driven source and they are supported by the following observations (Dangel et al.; 2003):

- The relative narrow frequency range of the signal (1.5-4Hz).
- The mean absolute power of the hydrocarbon tremor depends on the level of the environmental noise.
- The power of the signal seems to be proportional to the total hydrocarbon-bearing layer thickness of the reservoir.
- Three component recordings show a trough instead of a peak in the H/V-ratio.
- Preliminary tests using a directional sensitive sensor setup showed that the signals causing the anomaly originate from the reservoir direction.

Direct numerical simulations using Navier-Stokes equations show that pores which are partially saturated with oil and gas exhibit a resonance frequency. This resonance mechanism can be approximated by a damped oscillator model. Depending on the geometry of the pores, the oscillator models are either linear or nonlinear (Holzner et al., 2006). We couple the oscillator model to a one-dimensional wave propagation equation. We study under what conditions the resonance of the oil filled pores is activated and under what conditions the resonance frequency can be measured at the surface. In particular, we investigate the coupling between the porous reservoir material and the ambient rock material and the subsequent propagation of the resonant waves to the Earth surface. With a finite-difference time reversal approach (see below) we are currently improving the possibility to localize the origin of the low-frequency anomaly.

Time Reverse Modeling: A method to localize hydrocarbon tremors

Localization of seismic events is very important in seismology and exploration. The localization helps to detect active seismic zones and to assess the geometry of the subsurface geology. Current procedures imply that the seismic event is visible and reliably definable on seismograms from several stations of a seismic network. Weak events are either badly identified or generally overlooked. Time reverse modeling is a method to also localize such weak events (Fink 1999; Gajewski et al. 2005). The seismograms measured at the stations are reversed in time and are afterwards used as boundary values for the reverse modeling. It has been shown that the reverse modeling is able to track down events for an S/N-ratio lower than one.
Time reverse modeling is also a promising approach for the localization of hydrocarbon microtremors. A direct and quick detection of hydrocarbon reservoirs is of central interest for the development of new oil or gas fields. We apply an explicit finite difference method based on a velocity-stress formulation for numerical time reverse modeling. We perform numerical feasibility studies and show that, if there is a steady origin of low-frequency seismic waves within a reservoir, we can reveal the location of the reservoir in applying time reverse modeling. Time signals of only a few sensors (as usually available for field campaigns) are enough to detect the reservoir in a geological complex environment. A further development of this application will be to visualize more than one reservoir in the subsurface, for example stacked reservoirs.

Time Reverse Modeling: Method & Procedure

Time reverse modeling is an effective tool to detect the locality of a steady origin of low-frequency seismic waves. First, a realistic forward model produces synthetic seismograms resulting from microtremors in a reservoir. The synthetic microtremors are approximated as low-frequency signals with a fundamental frequency of about 3Hz and a range between 1.5Hz and 4.5Hz. The spectras are comparable with field observations in Brazil (Figure 3). The seismograms are reversed in time and are then used as boundary values at the location of the sensors for the time reverse model. Snapshots showing the current velocity at every grid point are produced at specific time steps during the reverse modeling. High velocities are supposed to indicate the location of a specific source of the forward model. After some time of reverse modeling the maximum velocities are expected to show the pattern of the reservoir.

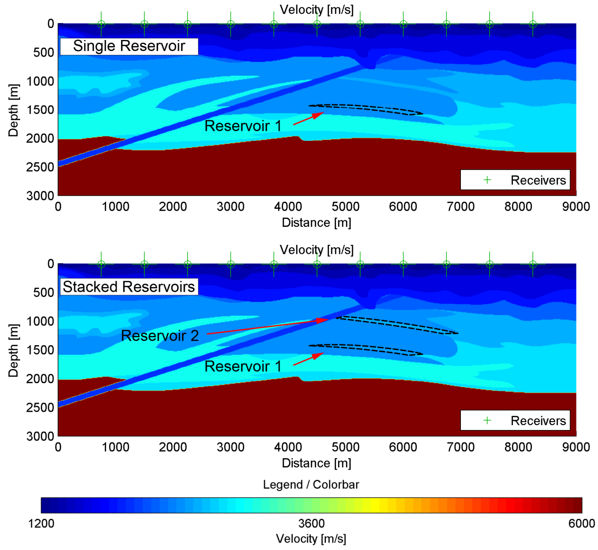

Figure 3: *Model setup: The model consists of ten sediment units and a basement unit. The lower part of the model domain is cut by a fault. For the first numerical study (Single Reservoir, top) one reservoir defines the area of seismic sources. For the second numerical study (Stacked Reservoirs, bottom) the source area is defined by two reservoirs which are stacked.*

The numerical modeling algorithm is similar to the rotated staggered grid finite-difference technique described by Saenger et al. (2000). The two dimensional numerical grid is rectangular. All computations are performed with second order spatial explicit finite difference operators and with a second order time update.
The grid contains 901 horizontal and 301 vertical nodal points with an interval of 10m in both directions. The model setup is similar to the geological situation (Figure 2) observed in Voitsdorf (Austria) (Graf et al. 2007). Each model unit is homogeneous and isotropic. There are ten different non-planar sediment model units with P-wave velocities increasing from 1200m/s (top layer) stepwise by 200m/s up to 3000m/s (bottom layer). The velocity is defined by varying Young's Modulus and a constant density of 2000kg/m^3 is applied for all sediment units. The crystalline basement model unit is defined by a density of 3000kg/m^3 and a Young's Modulus of $1.08*10^{11}$N/m^2 resulting in a P-wave velocity of 6000m/s. The lower part of the model is cut by a fault with a density of 2000kg/m^3 and a Young's Modulus of $8*10^9$N/m^2 resulting in a P-wave velocity of 2000m/s. The reservoirs with a thickness of about 50m and a lateral extension of about 2000m are positioned close to the middle of the model domain. They have a density of 2000kg/m^3 and a Young's Modulus of $1.25*10^{10}$N/m^2 resulting in a P-wave velocity of 2500m/s. All S-wave velocities are ~1.4 smaller than the corresponding P-wave velocity.

Time Reverse Modeling: Numerical case studies

A numerical study for one reservoir and another study for two reservoirs are performed (Figure 3). Snapshots during the reverse modeling show an accumulation of high velocities in the vicinity of the sources which were applied in the forward model (Figure 4).

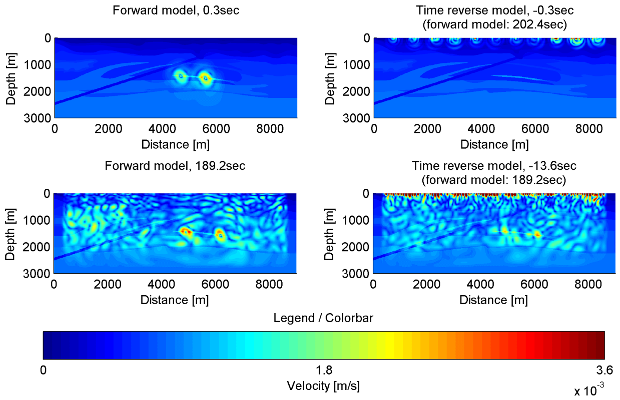

Figure 4: *Snapshots of the forward model (left coloumn) and time reverse model (right column) for the single reservoir model. The top figures show the first steps of both simulations. The bottom figures correspond to the same time. The microtremors known from the forward model are visible in the time reverse model.*

The inaccuracy is, as discussed by Gajewski et al. (2005), considerably small because the error of maximal 100m is much smaller than the wavelength of the waves at the central frequency. The error is therefore negligible. The area where the highest velocities occurred during the reverse modeling delineates the area in which the point sources of the forward model were distributed (Figure 5). The accumulation of high velocities is dense enough to distinguish between the two stacked reservoirs. The high velocity areas for the model with two reservoirs do not correspond as good to the reservoir areas as compared to the model with one reservoir. The noise at the surface is a result of the generation of surface waves. We expect that a denser spacing of receivers and also receivers located in vertical borehole profiles might be helpful to reduce most of this noise.

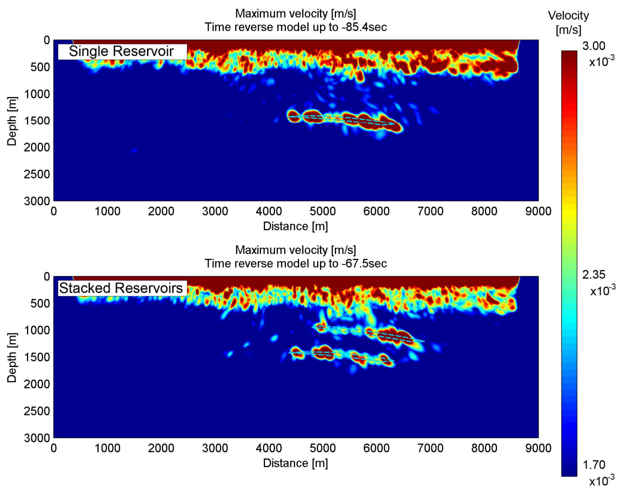

Figure 5: *Distribution of maximum velocities in the reverse modeling simulations. Both models with one (top) and two reservoirs (bottom) show a focus of high velocities in the area of the reservoirs, which are zones of microtremor sources in the forward models.*

Time Reverse Modeling: Discussion

We have shown that the locations of microtremors in the subsurface can be localized with time reverse modeling. It can be applied to reveal potential “hydrocarbon microtremors” reliably as the error of localization is negligible relative to the wavelength of the central frequency and relative to the extension of reservoirs. The numerical results are also promising for the detection of several, stacked reservoirs. Further development of this technique would be to distinguish between several types of source. Other sources might be external sources or artificial noise. The next step of development will be to apply this technique to real data. Thereby, time reverse modeling can also be applied to localize disturbing signals. We hope that the application of time reverse modeling will allow us to determine whether the “hydrocarbon microtremors” really originate from hydrocarbon reservoirs.

H/V-ratio vs. V/H-Hydrocarbon Indicator

The movements of the Earth surface generated by the omnipresent ambient seismic background noise, and their corresponding Fourier spectra for frequencies above 1 Hz, are usually referred to as microtremor (Bard, 1999; and references therein). It is well known that near-surface geological structures can characteristically modify the spectral content of microtremors. One example is the resonant amplification due to a soft soil layer. This effect leads to amplification at the fundamental S-wave resonance frequency, f_0, of the soil layer which is given by the so-called quarter wavelength rule (Pujol, 2003):

$$f_n = (2n+1)\frac{v_S}{4H} \quad \xrightarrow{n=0} \quad f_0 = \frac{v_S}{4H}, \qquad (1)$$

where v_S is the S-wave velocity in the soil layer with thickness H. The amplification peak is especially stable in the spectral ratio of the horizontal (H) to the vertical (V) component of ground motion (H/V-ratio).
As reprted above, low-frequency (< 10 Hz) spectral anomalies in surface microtremor signals have recently also been used as direct hydrocarbon indicators. Most of those empirical observations are based on the vertical component of microtremor motion only. However, Dangel et. al. (2003) analyzed some 3C recordings and found a trough in the H/V-ratio within the low-frequency band. Motivated by these observations of a characteristic modification of the H/V-ratio above hydrocarbon reservoirs, the main aim of this study is to analyze spectral ratios of microtremors with respect to a hydrocarbon bearing structure in Austria and particularly to initiate the discussion about the applicability of spectral ratios for hydrocarbon reservoir detection and characterization. We indroduce peaks inbetween 1 and 6 Hz in the V/H-ratio as an additional hydrocarbon indicator.

Stability of spectral ratios of microtremor

In this section we investigate the temporal and spatial stability of spectral ratios of microtremor. In particular, we empirically demonstrate that spectral ratios are, compared to single component spectra, more stable with time and therefore in general more suitable to derive information related to the site-specific geological structures (Figure 6). Taking the ratio between the spectrum of the horizontal and vertical ground motion (or vice versa), ideally eliminates the dominance of the source characteristics (which are usually unknown in microtremor studies) and thus provides a more stable measure for site-specific properties.

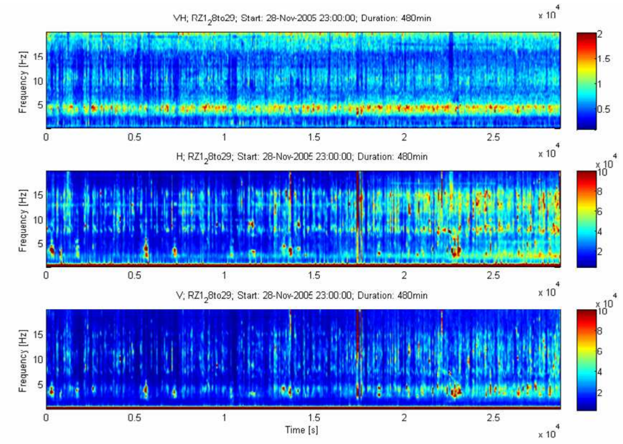

Figure 6: *V/H-microtremor-spectrogram above an oil reservoir (top graph). The measurement time was about 8 hours. For comparison we show the H- and V-components on a seperate graph (middle and bottom, respectively). The time-stability of the V/H-Hydrocarbon Indicator slightly below 5Hz is remarkable.*

In Voitsdorf the single component spectra for both the horizontal and vertical microtremor motion measured at station RZ1 vary considerably from day to day (Figure 7, A1-A3). However, this is not the case for the spectra of the H/V-ratio, where all the signals show a very similar spectral shape. This observation suggests that single component spectra (H and V) show more variation with time than the H/V-ratio. In addition, the shape of the H/V-spectra changes considerably from site to site but is remarkably constant with time at one specific location (Figure 7, B1-B3).

V/H-ratio: Observations across an oil and gas field

Dangel et al. (2003) systematically measured a trough in the low-frequency range of the H/V-spectrum of microtremor at the Earth surface above hydrocarbon bearing structures. If this observation is consistent, we expect increased amplitudes in the low-frequency range (< 10 Hz) of the V/H-spectrum (rather than the H/V-spectrum) related to the presence of hydrocarbons. Therefore, we have measured microtremors at eight stations along an N-S cross-section across an oil-reservoir in Voitsdorf, Austria.

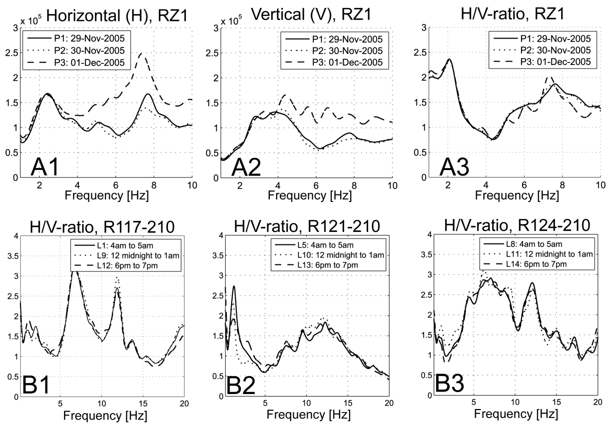

Figure 7: *(A1-A3) Temporal stability of spectral ratios (here H/V-ratio) compared to single component spectra (H and V). (B1-B3) Spatial and temporal stability of spectral ratios of microtremor. The distance between the stations is 750 m and 1000 m, respectively*.

The V/H-spectra were then simply derived by taking the inverse of the values of the H/V-ratio. Each V/H-spectrum has been calculated out of 60 minutes of continuous microtremor recording from 4 AM to 5 AM UTC (Figure 6).We picked the amplitude of the dominant peak in the 1- to 6-Hz range for each V/H-spectrum (triangles). Measurement L7 does not show any dominant peak in this range, thus no value could be determined for the corresponding location. The picked amplitudes are plotted along the cross-section (thick line) and compared to a profile from a reflection seismic survey (Figure 8).

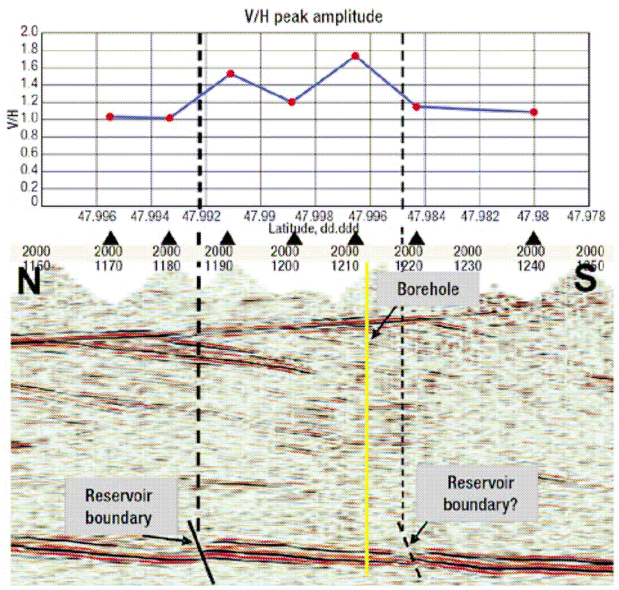

Figure 8: *The maximal value of the V/H ratio within the 1- to 6-Hz range for each sensor is shown over the southern part of a fully explored reservoir in Voitsdorf, Austria. This alternative to the standard H/V technique is an additional, proprietary attribute for microtremor hydrocarbon detection.*

The dashed lines indicate the reservoir boundary towards the north (thick dashed line) and the expected reservoir boundary towards the south (thin dashed line). These boundaries are interpretations based on reflection seismic data, and in addition a producing borehole exists (white line) proving the presence of hydrocarbons at this location. The two thin lines display V/H-profiles derived from measurements along cross-sections parallel to the one described in the previous paragraph. These two N-S cross-sections are located 250 m to the east and to the west, respectively.
The measured values of the V/H-amplitude show a characteristic change across the hydrocarbon reservoir, namely that higher values and larger variations of the V/H-amplitude can be observed above the reservoir.

V/H Hydrocarbon Indicator: Discussion

The presented observations suggest that increased amplitudes and larger variations of the V/H-ratio of microtremor in the low-frequency range (here 1 to 6 Hz) are an attribute related to the presence of hydrocarbons in the subsurface. However, not all the measurements clearly confirm this conclusion: The western line exhibits generally quite low values and on the eastern line the third station (from the south) shows an unexpected low value. But in our opinion this does not disprove the correlation of the attribute with the reservoir location. The signal might be obscured by strong surface noise or the geological complexity might be such that the effect does not show up in the measurements.

Discussion and Conclusions

The mechanism causing the observed hydrocarbon tremors is still an open rock physical question. Therefore, our theoretical and numerical findings will be compared with measured data from known oil fields and available geological and geophysical information, such as rock type, well logs and other relevant reservoir parameters, will be implemented in our multiscale research strategy in order to test the validity of the models. In particular, the wave types which generate the spectral anomalies and which represent the source are analyzed by investigating the ratios of spectra of the horizontal and vertical velocities and by comparing measurements at different locations to measurements done at well known reference locations. With a time-reversal approach we are able to localize continious microtremor sources. Another focus of our research is filtering and removing of noise caused by anthropogenic and industrial activities.

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