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Carbon Sequestration

ALEXANDRA IVANOVA*

ABSTRACT

Carbon sequestration technologies are to reduce the carbon dioxide (CO_2) emissions and in turn, to mitigate global climate change without adversely influencing energy use or hindering economic growth. However, various requirements must be met before these technologies will be accepted by the public for wide-scale implementation. Comprehensive long-term monitoring programs are inevitable to reduce corresponding risks. Such programs include both theoretical and applied scientific studies related to the characterization of the sub-surface and to understand the processes associated with the carbon sequestration technologies. Geophysical monitoring is an essential tool for the reservoir characterization and for providing information on the injection related processes. The seismic method has proven to be a suitable technique for qualitative and quantitative monitoring CO_2. The mass estimation of the injected CO_2 visible in seismic data is important for assessing storage efficiency.

***Key words*:** xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx

INTRODUCTION

CO_2 capture and storage (CCS) technologies are being given consideration to reduce CO_2 emissions and in turn, to mitigate global climate change without adversely influencing energy use or hindering economic growth (IPCC, 2005). However, various requirements must be met before CCS will be accepted by public for a wide-scale implementation and safety of

Helmholtz Centre Potsdam, GFZ German Research Centre for Geosciences, Centre for Geological Storage, Telegrafenberg, 14473 Potsdam, Germany
**Corresponding author*: E-mail: aivanova@gfz-potsdam.de

reservoirs is the key problem facing CCS. A corresponding long-term monitoring program including geophysical studies is inevitable (JafarGandomi and Curtis, 2011).

3D seismic time-lapse surveys (4D seismics) have proven to be a suitable technique for qualitative and quantitative monitoring of injected CO_2 (Ivanova *et al.,* 2012; Chadwick *et al.,* 2010). The right seismic source is essential for such studies (Yordkayhun *et al.,* 2009). Forward modeling of the seismic response to CO_2 fluid substitution in a storage reservoir is a further important step of the studies (Ivanova *et al.,* 2013a). CO_2 mass estimation visible in 4D seismic data is important for assessing storage efficiency. The minimum degree of accuracy is a crucial issue in such investigations (Ivanova *et al.,* 2012). It is well known that temperature and pore pressure in the reservoir are major parameters influencing CO_2 storage and migration in saline aquifers (Ivanova *et al.,* 2013a; Ivanova *et al.,* 2013b).

4D SEISMICS FOR CCS

The Right Seismic Source and Seismic Processing and Interpretation

The right seismic source is one of the most important requirements of the reflection seismic experiment (*e.g.*, Feroci *et al.* 2000). It can be chosen using criteria directly related to the nature of the problem. First of all, the energy content has to be high enough in order to acquire adequate information for the required investigation depth. Secondly, the frequency content must be high and broad enough in order to achieve the necessary resolution. There are also other factors to be taken into consideration. These include the pulse coherency and signal-to-noise ratios. Certainly the sources have to be convenient and safe in exploitation. Repeatability has also to be taken into consideration. All these conditions "trade off" with the cost of the survey. As a matter of fact, the main aim of the studies on the source comparison is to show how the media with given characteristics responds to each source (*e.g.*, Yordkayhun *et al.,* 2009).

The purpose of seismic processing is to transform the acquired data into an image that can be used to infer the sub-surface structure (Yilmaz, 2001). As for the seismic interpretation, it is to obtain a coherent geological overview based on the processed seismic reflection data. One aim is to produce structural maps that reflect a spatial variation in depth of certain geological layers. There is always a degree of uncertainty in any seismic interpretation (Yilmaz, 2001).

Seismic data processing is composed of basically five types of corrections and adjustments: time, amplitude, frequency-phase content, data compressing (stacking) and data positioning (migration) (Yilmaz, 2001).

Time adjustments can refer to dynamic and static categories. The normal move-out (NMO) correction refers to the dynamic category. It corrects for the difference in travel-times of the reflections from a horizontal reflecting surface due to variations in the source-geophone distance (Yilmaz, 2001). The static correction is a correction applied to geophysical data to compensate for the effect of near-surface irregularities, differences in the elevation of shots and geophones, or any application to correct the positions of source and receivers.

Amplitude adjustments correct the amplitude decay with time due to spherical divergence and energy dissipation in the earth (Yilmaz, 2001). The amplitude decay analysis provides an indication of the source-generated energy and signal penetration depth (Yordkayhun *et al.,* 2009).

The frequency and phase content of the data are manipulated to enhance the signal and attenuate noise (Yilmaz, 2001). Appropriate band-pass filters (single-channel filtering) can be selected by scanning the data in different narrow frequency bands. Deconvolution is an inverse filtering technique used to compress an oscillatory (long) source waveform into as near as possible a spike (unit-impulse function). Near-surface reverberations can often be attenuated through the deconvolution approach.

A seismic data compression technique that is generally used is the common midpoint (CMP) stack. It sums all offsets of a CMP gather into one trace. This technique is very important for reflection seismics, because reflected seismic energy is usually very weak and it is imperative to increase the signal to noise ratio of most data (Yilmaz 2001). Migration produces a final section or volume in the depth or in time domain that is generally used as the basis for geological interpretation (Yilmaz, 2001).

3D Seismic Surveys

3D seismic surveying has become a common exploration and production tool since 3D images usually contain less source-generated noise and show a dramatic increase in information and accuracy of structural images of the subsurface in comparison to 2D images (Sheriff and Geldart, 1995; Cordsen *et al.,* 2000).

In the 3D seismic method we record many lines of receivers across the earth's surface. The area of receivers we record is known as a "patch" or "template" (Juhlin *et al.,* 2007). Usually we employ lines of source points laid out orthogonally to the receivers. By sequentially recording a group of shots lying between two receiver lines (referred to as a "salvo") and centered within the template, we obtain uniform one-fold reflection information from the subsurface area that is one quarter of the useful surface area of the template (Cordsen and Galbraith, 2002). Although we usually record a large square or a rectangular template, the useful data at our zone of interest is offset limited by several geophysical factors. Therefore, we often consider the useful area of coverage as a circle with the radius equal to our maximum useful offset (Cordsen *et al.,* 2000). By moving the template and recording more salvos of source points, we accumulate an overlapping subsurface coverage and build a statistical repetition over each subsurface reflecting area (bin).

The quality of the sub-surface image obtained can be related to the statistical diversity of information recorded for each cell of the sub-surface coverage (known as a "bin") (Cordsen *et al.,* 2000). The more observations containing unique measurements of echoes from a certain area that are obtained, the more successful we are in the reconstruction of the subsurface geological configuration that causes these observations (Biondi, 2006).

3D image quality is sensitive to offset squared and controls our selection of line grid density. The fact that the 3D coverage is proportional to offset squared means that the economics of our program (grid density) and the success of our program (image quality) are very sensitive to our evaluation of useable source-receiver offsets. This factor is to be of prime importance in a 3D design (Cordsen and Galbraith, 2002).

Each trace of a 3D survey represents a different source-receiver offset. Also each trace represents a different source-receiver azimuth. The azimuth adds a dimension of statistical diversity that is very helpful to the imaging procedure (Cordsen *et al.,* 2000).

Feasibility Study for the 4D Seismic Method

4D seismics consist of a 3D seismic survey, which is repeated one or more times at the same site in order to detect temporal changes in the subsurface (Ivanova *et al.,* 2012). The first step of a feasibility study is a rock physics analysis of the reservoir at the research site and modeling the effects of rock properties on changes in fluid fill, pressure and temperature (Ivanova *et al.,* 2013a; Ivanova *et al.,* 2013b).

The following factors are critical in the physical feasibility of the time-lapse seismic analysis (Wang *et al.,* 1997): frame elastic properties of reservoir rocks, contrast in pore fluid compressibility, nature of the injection process and reservoir parameters (depth, pressure, temperature, etc.)

The frame of reservoir rocks is defined as rock with empty pores. Rocks with low frame elastic properties like unconsolidated rocks and rocks with open fractures are the most favorable for the successful time lapse seismic analysis. In order to monitor fluid changes, a contrast in pore fluid compressibility is required between the baseline reservoir fluid and the monitor reservoir fluid. Changes of the reservoir seismic properties result from the injection activity; hence it is important to understand how the injection process affects the reservoir. For instance, high injection pressure and rates may fracture the reservoir rock and seismic velocity is very sensitive to fractures. Shallow reservoirs with higher porosity and temperature are easier to monitor with time lapse seismics (Wang *et al.,* 1997). The effects of pressure changes due to CO_2 injection are more difficult to monitor (Ivanova *et al.,* 2013b).

Acquisition and Processing of 3D Time-Lapse Seismic Surveys

The repeatability between baseline and monitor surveys is the most important parameter of the time-lapse seismic acquisition. The source and receiver positions in the baseline and monitor surveys should be kept at the same locations to the greatest extent as possible. Brown and Paulsen (2011) showed repeatability statistics from a number of 4D surveys in the North Sea. High quality 4D survey data with NRMS levels less than 10% were obtained with combined source and receiver position errors around 25–40 m. However in real acquisition, positions of a sources and receivers cannot always be replicated due to surface water currents for marine surveys and changes in infrastructure for production at a location (*e.g.*, an oil platform). There are also other factors that could possibly have an effect on repeatability (*e.g.*, ambient noise, which can easily vary from one survey to another). For land surveys, near surface effects vary due to acquisition in different seasons and weather conditions (Kashubin *et al.,* 2011). The source signature can also vary from one survey to another (Bacon *et al.,* 2007). Nowadays, permanent reservoir monitoring systems are applied at some oil fields. It means receivers are permanently placed in the same positions to reduce the acquisition differences.

Processing steps including static corrections, mute design, pre-stack deconvolution, stack, migration velocity derivation and amplitude balancing affect the results for baseline and monitor surveys on land data. Datasets from different surveys should therefore be processed in parallel to permit a comparison. Specialized time-lapse processing should be applied on datasets to improve the repeatability (Ross *et al.,* 1996). Normally in the time-lapse processing a baseline survey is used as a reference volume and repeat surveys are processed to match time, phase, frequency and amplitude of the baseline survey. After the processing, differences in the seismic images between the surveys represent changes in the reservoir properties (assuming there are no artifacts) (Ivanova *et al.,* 2012).

Interpretation of 4D Seismic Surveys

After the time-lapse seismic processing step, the datasets from different surveys can be compared. The difference in Two Way travel-Time (TWT) to a reflection at the bottom of the reservoir and one at the top of the reservoir can be monitored. In the ideal case, the TWT to reflections above the reservoir will not change between different surveys. In the reservoir, seismic velocities will change due to injection or production, *i.e.*, the TWT thickness of the reservoir will change. Below the reservoir, the TWT of seismic events will also alter (Ivanova *et al.,* 2012). For a thick reservoir layer this effect can be quite large, ranging from a few to 10 milliseconds (ms). Normally the time shift can be easily picked if the seismic data have a reasonably good S/N ratio. As for time-lapse amplitude anomalies, they can be very useful to map fluid changes in the reservoir. For example, in Ivanova *et al.* (2012) the application of a cutoff based on the amplitude change map was crucial in quantitative 4D seismic data interpretation at the Ketzin site. Time-lapse seismic images are used to make estimates of the imaged amount of CO_2 (Chadwick *et al.,* 2010; Ivanova *et al.,* 2012). It is important for assessing storage efficiency. The minimum degree of accuracy is a crucial issue in these investigations. Such minimum thresholds establish the smallest amount of CO_2 that is possible to be monitored by means of surface-based methods (JafarGandomi and Curtis 2011). At Ketzin, quantification of the mass of the injected CO_2 was performed using the time-lapse seismic data, petrophysical investigations on core samples and *in-situ* CO_2 saturation from pulsed neutron gamma (PNG) logging as input (Ivanova *et al.,* 2012) and multiphase flow simulations for two temperature scenarios in the reservoir (Ivanova *et al.,* 2013a).

AVO/AVA

Since W.J. Ostrander published in 1984 his paper about amplitude versus offset (AVO) effects in sands filled with gas (Ostrander, 1984), AVO analysis of seismic reflections has become an important tool for the hydrocarbon prospecting. Some applications of AVO analysis in the oil industry are as follows: (1) to predict and to map hydrocarbons, (2) to distinguish lithology and map porosity in clastics and carbonates and (3) to perform pore pressure prediction and characterize reservoir changes for time-lapse seismic studies (Chiburis *et al.,* 1993). True amplitude of seismic data should be preserved during the seismic processing for AVO analysis. As an important technique for quantitative petrophysical interpretation of seismic data, AVO analysis is worth testing in the field of CO_2 monitoring, which is facing challenges similar to those in oil and gas reservoir management. Brown *et al.* (2007) used AVO analysis to estimate CO_2 saturation from modeling data. At the Sleipner storage site in the North Sea the standard AVO failed due to presence of thin CO_2 layers. Therefore a modified AVO method was used to estimate thickness of CO_2 layers (Chadwick *et al.,* 2010). AVO modeling has been used to distinguish the effects of pressure and CO_2 saturation after the gas injection at the Wey burn Field in Canada (Ma and Morozov, 2010). After measuring elastic velocity under several different gas saturations in the laboratory, standard AVO analysis was applied for the supercritical CO_2 at the SACRO oil field in United States (U.S.) (Harbert *et al.,* 2010).

The first equations describing how amplitudes of reflected and transmitted P- and S- waves depend on the angle of incidence and properties of the media above and below the interface were published by Zoeppritz (1919). These equations are quite complicated. Aki and Richards (1980) and Shuey (1985) derived approximation equations. A further simplification of these equations gives the following equation:

$$R(\theta) = P + G\sin 2\theta,$$

where R is the reflection coefficient, P is the intercept, G is the gradient and θ is the angle of incidence on the interface.

Using this equation on pre-stack common-depth-point (CDP) gathers, we obtain two basic AVO attributes: the intercept (P) and the gradient (G) and the AVO products like "P*G". There are some other AVO related attributes, such as the reflection coefficient difference introduced by Castagna and Smith (1994). Smith and Gidlow (1987) created the fluid factor. The "lambda*rho" ($\lambda\rho$) and "mu*rho" ($\mu\rho$) were introduced by Goodway *et al.* (1997). According to the impedance contrast between sand filled with gas and shale, the reflection can be divided into four following classes (Rutherford *et al.* 1987; Castagna and Swan 1997).

"Class 1" corresponds to high-impedance sands. It means the impedance of the sand layer is higher than the surrounding medium and the amplitude decreases with the increasing offset. In this case, if an adequate offset range is available, the amplitude can change polarity.

"Class 2" is near-zero impedance contrast sands. In this case the reflection coefficient of the sand/shale interface at normal incidence could be minus or plus. Actually the former option is called "Class 2". Ross and Kinman (1995) name the latter option "2p". In fact, this class may or may not correspond to amplitude anomalies on stacked data.

"Class 3" refers to low impedance sands. In this case the sand layer, normally unconsolidated, has lower impedance than the surrounding medium (Juhlin and Young, 1993) the amplitude increases with the offset. There are clear amplitude anomalies in this case, normally called bright spots.

"Class 4" means a very large impedance contrast and a small change in Poisson's ratio. Actually "Class 4" is a reversal of "Class 3".

A common method of AVO analysis is the AVO crossplot (Ross, 2000). It is a very helpful and intuitive way to present the AVO data and can give a better understanding of rock properties, than by analyzing standard AVO curves (Ross, 2000).

In 1993, C. Juhlin and R. Young presented a method how the AVA response of a thin bed may be approximated by modeling it as an interference phenomenon between plane P-waves from a thin layer, in which the contrast in elastic properties between the layer and surrounding rock is small. When a reflecting layer is thick enough in comparison to the seismic wavelength then reflections from the top and the bottom of a layer are independent of one another. If the layer thins, the reflections interfere and finally appear as a single reflection when the layer is sufficiently thin. By the time delay modeling it was shown that thin layers imbedded in homogeneous rock can significantly affect the AVO response observed compared to that one of a simple interface of the same lithology. This effect of a low-velocity thin layer is less than that of a high-velocity thin layer with a comparable simple interface AVO response. The both of statements are valid when the impedance contrast is low. As the contrast in elastic properties increases, the approximation used in the above modeling becomes quite poor. In this case it is necessary to include contributions to the reflected waveform from P-wave multiples and converted shear waves. Juhlin and Young (1993) showed a dramatic dependence of seismic response on wavemode contributions for a coal seam.

In Ivanova *et al.* (2013a) this method was used for modeling of the AVO response of CO_2 injection at the Ketzin site. The results indicate it is theoretically possible to discriminate between the CO_2-saturation-related changes at high CO_2 saturations and pore-pressure-related changes. But the modeled changes in the AVA gradient are rather small and therefore unlikely to be retrievable from the field data (Ivanova *et al.,* 2012) with a signal/noise ratio of 2-3. In addition, the actual seismic response may be due to a combination of saturation and pore pressure effects. It would be a further complication for any true discrimination. In case the CO_2 saturation effect dominates the AVO/AVA response at Ketzin, cross-plots of the modeled AVO/AVA gradient and intercept (Ivanova *et al.,* 2013b) can be potentially used to determine CO_2 saturation levels in the reservoir at the Ketzin site on the real seismic data (the AVO/AVA intercept and gradient).

M. Landro (2001) has derived approximate formulas for computing saturation- and pressure-related changes from time-lapse seismic data and successfully tested them on a time-lapse seismic data set. The formulas are explicit expressions related to near- and far-offset stacks. They are well suited for direct implementation in a processing package. It is necessary for this method to obtain input equations from a rock physics model that relates changes in the seismic parameters to changes in pressure and saturation. This method discriminates well, in some cases, between fluid-saturation and pore-pressure changes (Landro, 2001). It is useful to obtain separate attribute cubes for fluid-saturation and pore-pressure changes, because from a reservoir management view such data cubes are valuable since they can be compared directly with well observations and extended to areas between wells. This method is a complementary tool for monitoring well performance and planning infill wells in a mature reservoir (Landro, 2001).

CO_2 AND ROCK PHYSICS

Rock physics (petrophysics) concerns relationships between physical properties of rocks and geophysical observations (Mavko *et al.,* 1998). As for CCS, these relationships refer to understanding the behavior of the injected CO_2 in geological formations (Lei and Xue, 2009). Interpretation of time-lapse seismic data depends on the relationship between seismic parameters and typical reservoir parameters to be mapped such as for instance pore pressure changes and fluid saturation changes (Vanorio *et al.,* 2010). Petrophysics provides a link for bridging a gap between these two types of parameters.

In this regard the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy (DOE) and Stanford University have established a unified rock physics framework for quantitatively interpreting seismic observations (www.netl.doe.gov). The research focuses on developing a deterministic workflow that will allow an expert to select host formation properties as well as injection and storage conditions, to generate seismic reflection records of the reservoir formation as the CO_2 within changes in space and time (Vanorio *et al.,* 2008; Vanorio *et al.,* 2010; Vialle and Vanorio, 2011; Vanorio *et al.,* 2011a; Vanorio *et al.,* 2011b).

If a secure storage cannot be verified via geophysical monitoring, it is not possible to use such a reservoir for CCS (JafarGandomi and Curtis, 2011). Main goals of recent research on rock physics applied to CCS (Vanorio *et al.,* 2008; Vanorio *et al.,* 2010; Vialle and Vanorio, 2011; Vanorio *et al.,* 2011a; and Vanorio *et al.,* 2011b) are to generalize laboratory data, to better understand the underlying rock physics and chemistry behind observations and to conceive optimized models involving frame substitution schemes.

Integration of rock physics with the 4D seismic technology is an effective tool for quantitatively characterizing reservoir dynamics associated with hydrocarbon production and environmental engineering (Vanorio *et al.,* 2011a). From the first laboratory experiments exploring time-lapse effects of temperature on velocity in heavy-oil-saturated samples (Nur 1989) and the earliest field applications (Greaves and Fulp, 1987; Pullin *et al.,* 1987), 4D seismic technology has developed to progressively enhance seismic signal fidelity, repeatability and interpretation (Lumley, 2001).

The Gassmann's model (Gassmann, 1951) is used as a general basis for interpreting the effect of fluids on both log and seismic velocity data. The model scheme predicts changes in moduli and density of the rock by replacing one pore fluid with another and then converting the predicted moduli and density back to velocities. The rock-fluid interaction is treated as a purely mechanical problem and changes in seismic velocity depend only on the compressibility and density of the fluid, on the physical parameters controlling them (Batzle and Wang, 1992) and on the density and elastic moduli of the rock frame. In spite of some uncertainties, this approach was successful for the sandstone reservoir at the Ketzin site initially saturated with simple formation brine at the depths of about 650 m, temperature 34-38°C and a pressure 6-7.5 MPa in which food grade CO_2 is injected (Ivanova *et al.,* 2012).

Although it is a common practice to include time-variant effects on properties of the fluid and the rock frame due to variations of physical parameters such as stress and temperature, which respectively induce compaction and fluid-phase changes (Nur *et al.,* 1984; Lumley, 1995; Guilbot and Smith, 2002; Hatchell and Bourne, 2005; Ivanova *et al.,* 2013a, Ivanova *et al.,* 2013b), the basic assumption of the Gassmann's theory is that the fluid and the rock matrix do not interact and interpretation of seismic data almost never includes coupled chemo-mechanical effects on the properties of the frame (Vanorio *et al.,* 2011a). There is a possible problem, that is, a massive injection of CO_2 can alter the geochemical equilibrium between reservoir and formation water. Numerical studies show (*e.g.*, Martens *et al.,* 2012) that a considerable part of total injected CO_2 may get dissolved into the formation fluid. There is a need to expand the rock-physics tool kit and to provide a set of empirical relationships between time-variant effects of the geochemical process and rock frame properties.

Detectability depends on rock porosity and on CO_2 saturation, as well as on the thickness and depth of the storage formation (JafarGandomi and Curtis, 2011). In particular, density and resistivity changes are detectable only above a threshold saturation that decreases significantly with increasing depth and decreasing thickness of the storage formation. Gassmann's theory (using the patchy saturation model) is successful regarding quantitative seismic monitoring at the Ketzin site using petrophysical experiments on two samples (Ivanova *et al.,* 2012). However, forward modeling for other sites shows that errors from ignoring the specific properties of CO_2 and its aqueous solution can affect crucially predicted velocity changes (Vanorio *et al.,* 2010).

Analysis of the applicability of petrophysical parameters to CCS cannot be directly generalized for all storage sites at present. Results must be updated for each specific site. This analysis is effective for early stages of site selection and decision making where a rapid yet comprehensive initial estimate of the site-monitoring feasibility is required.

CONCLUSIONS

Seismic modeling and observations show that the effects of injected CO_2 on the 4D seismic data are significant, regarding seismic amplitudes and time delays. However, reservoir heterogeneity and seismic resolution, as well as random and coherent seismic noise are negative factors to be considered in seismic monitoring. Nevertheless, results of processing, including equalization and cross-correlation at the Ketzin pilot site indicate that the injected CO_2 can be monitored. Time-lapse seismic processing, petrophysical measurements on core samples and geophysical logging of CO_2 saturation levels allowed for an estimate of the total amount of CO_2 visible in the seismic data at the Ketzin pilot site to be made. This estimate is somewhat lower than the actual amount of CO_2 injected up to the time of the survey and it is dependent upon a choice of a number of parameters. In spite of this uncertainty, the close agreement (over 90%) between the injected and observed amount is encouraging for quantitative monitoring of a CO_2 storage site using seismic methods. Temperature monitoring is very important for quantitative seismic interpretation at a CO_2 storage site.

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