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Towards Quantitative Evaluation of Gas Injection using Time-lapse Seismic

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SUMMARY

Of particular concern in the monitoring of gas injection for the purposes of storage, disposal or IOR is the exact spatial distribution of the gas volumes in the subsurface. In principle this requirement is addressed by the use of 4D seismic data, although it is recognised that the seismic response still largely provides a qualitative estimate of moved subsurface fluids. Exact quantitative evaluation of fluid distributions and associated saturations remains a challenge to be solved. Here, an attempt has been made to produce mapped quantitative estimates of gas volume injected into a clastic reservoir. Despite the accuracy of the calibration using three repeated seismic surveys, time-delay and amplitude attributes reveal fine-scale differences though large-scale agreement in the estimated fluid movement. These differences indicate disparities in the nature of the two attributes themselves and highlight the need for a more careful consideration of amplitude processing for quantitative 4D seismic interpretation.

Introduction

Of particular concern in the monitoring of gas injection for the purposes of storage, disposal or IOR is the exact spatial distribution of the gas volumes in the subsurface and away from wells. In principle this requirement is addressed by the use of 4D seismic data, although it is recognised that the seismic response still largely provides a qualitative estimate of these gas distributions. Exact quantitative evaluation of subsurface fluid volumes and associated saturations remains a challenge to be solved. Past work has addressed the calibration of seismic for this purpose using well production data and threshold analysis (Huang et al. 2001), laboratory measurements (Langlais et al. 2005), well tie analysis (Meadows 2008) or direct comparison with simulation models (Sengupta and Mavko 2003). In these studies, consideration has been given to seismic amplitudes (Huang et al. 2001) and reflector time-shifts (Dumont et al. 2001) as possible attributes for monitoring purposes, but with conflicting results. Consequently, to further understand the quantitative nature of the 4D seismic signal, here we also analyse both amplitude and time-shift data. Specifically, our focus is multiple vintages of seismic used to monitor methane injected into a saline aquifer in the North Sea. In this case, use can be made of known well volumes of this light immiscible gas injected into homogeneous and highly porous reservoir sands to aid in a good quality calibration of the final spatial distribution estimates.

Dataset

Our dataset consists of repeated seismic surveys shot over a turbidite reservoir lying at 2km depth in the North Sea into which methane is injected. Injection starts in 1998 and continues for the period of the seismic monitoring. The base seismic is shot in 1993, and three seismic monitor surveys are acquired thereafter in 1999, 2000 and 2002, after 25, 37 and 53 BCF of gas injection respectively. The time lapse surveys have a fairly low NRMS of 21% on average, Figure 1 demonstrating the general seismic quality. In the portion of the structure where the well is drilled, there are three distinct and fairly homogeneous sands into which the gas is injected (Figure 2). These sands remain hydraulically isolated although some cross-flow may be possible at the fault locations. Because of the need to maintain pressure, daily injection gradually decreases after 1999 to ensure that the average reservoir pressure is held approximately constant during the acquisition of the monitor surveys. Thus, the time-lapse anomalies visible between the repeated 1999, 2000 and 2002 seismic are mainly due to gas volume or saturation changes. However, any seismic time-lapse changes taken relative to the baseline seismic shot in 1993 also contain the start-up pressure effect.

(a)
(b)

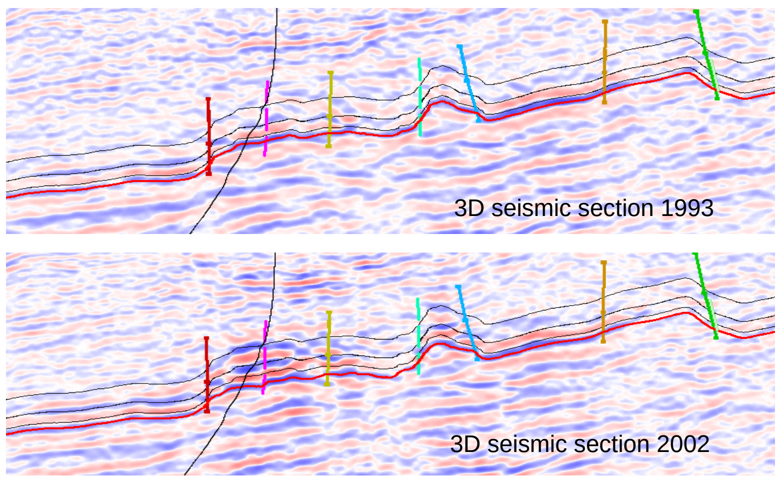

Figure 1 *NW(left) – SE (right) seismic sections for the area of interest. (a) Baseline 1993 section (before gas injection) with horizons and faults, and (b) the 2002 seismic vintage after four years of gas injection.*

Volumetric analysis using time shift attributes

Time-shifts (Δt) are calculated by picking the base reservoir reflector on the baseline seismic (blue trough in Figure 1) and for each of the monitor seismic surveys. Subtraction of the resultant picks from the two surveys then gives the required time-shifts that can be mapped across the area of interest around the injecting well. Time-shifts of up to 13ms are found, corresponding to a velocity slow-down due to the presence of gas. Following the strategy of Huang et al. (2001), we threshold the time-shift maps to allow us to define robust contiguous areas influenced by the changes in gas volume.

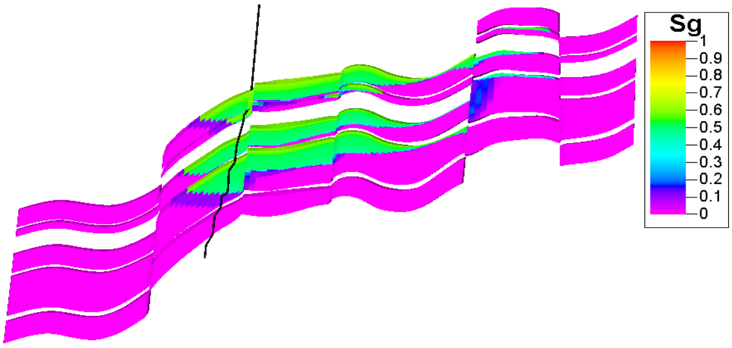

Figure 2 *Gas saturation predicted from the flow simulation model for July 2002. Model section is shown corresponding to the NW(left) – SE(right) seismic sections in Figure 1.*

The time-shift changes remaining after the thresholding procedure describe an area, Σ, of change on the map. For each cell within this area, the corresponding time-shift Δt is related to the gas volume ΔV_g sampled by the cell via

$$\Delta V_{gas} = S_{g\max}.\Phi.NTG.\frac{VV'}{2(V-V')}\Delta t(x,y).\Delta x.\Delta y, \qquad (1)$$

where V *is* the seismic wave velocity with no gas and V' the seismic wave velocity in the presence of the critical gas saturation S_{gmax} (Morrow and Melrose 1991). Φ and NTG are the sand porosity and net-to-gross respectively. By integrating (1) over Σ an estimate of the volume of injected gas for each seismic time-lapse period can be obtained. As the reservoirs are fairly homogeneous and their petrophysical properties vary only slowly across Σ, then the integral of S_{gmax}, Φ, and NTG can be approximated by their averages. This leads to the formula

$$V_{gas} = \left\{S_{g\max}.\Phi.NTG.\frac{VV'}{2(V-V')}\right\}^{mean} \iint_{\Sigma} \Delta t(x,y)dxdy, \qquad (2)$$

which predicts that the integrated time-shift changes are directly proportional to the total volume of injected gas V_g for a chosen survey time period. One modification to this is required when time-shifts between the baseline and any of the monitor surveys are being considered, as the total measured time-shift, Δt, in this case now includes a constant time-shift Δt_{pr} due to the pressure effect on the rock frame and fluids prior to 1999, such that $\Delta t = \Delta t_{gas} + \Delta t_{pr}$ and the time-shift due only to gas saturation is slightly masked. This effect adds a positive constant A to (1) as both pressure up and gas saturation soften the reservoir. In practice the combination of constant factors multiplying the integrand in (2) and the pressure factor A are not known with certainty, but can be estimated directly from the data by calibrating the time-lapse seismic with the well injection data. Thus, the three combinations of integrated time-shift from the 2002-2000, 2002-1999 and 2000-1999 signatures are cross-plotted against the injected volumes independently from the 2002-1993, 2000-1993 and 1999-1993 signatures (Figure 3(a)). An initial threshold of 0.5ms is used for the maps prior to integration, and this is refined upwards until the cross-plot points follow a straight line and also both lines have identical gradients. It is observed that the plot of signatures involving the baseline survey displays an offset corresponding to the pressure effect anticipated above, whilst the points generated between monitor surveys lie on a straight line which passes through the origin. The offset due to the pressure effect contributes on average 19% (or 2ms) to the total time-shift (for a 1000psi pressure increase). The common gradient of the lines now give us the calibration coefficient (the factor multiplying the integrand in (2)) that can be applied to the time-shift $\Delta t(x,y)$ in (1) at each location to convert the attribute map into a gas volume variation $\Delta V_{gas}(x,y)$ with appropriate correction for the pressure effect. The gas volume distribution predicted in this way for the 2002 survey is shown in Figure 4(a).

Volumetric analysis using amplitude attributes

A similar relation to (1) is also possible for amplitude attributes. For calculation of the amplitude maps, an *RMS* average is determined between top and base of the reservoir. Assuming that the pressure effect on the amplitudes is linearly additive an identical workflow is followed. The amplitude threshold is initially set at 5% of the maximum, and then adjusted as before until the best fit lines are achieved. In this process a lower limit is set to avoid introducing the spatially broad background noise level. The results are shown in Figure 3(b), which also reveal a small offset due to the pressure effect on the time-lapse signatures contributing 13% to the total amplitude. After obtaining the corresponding calibration coefficient, the resultant gas volume derived from the amplitude for 2002 can now be mapped in Figure 4(b).

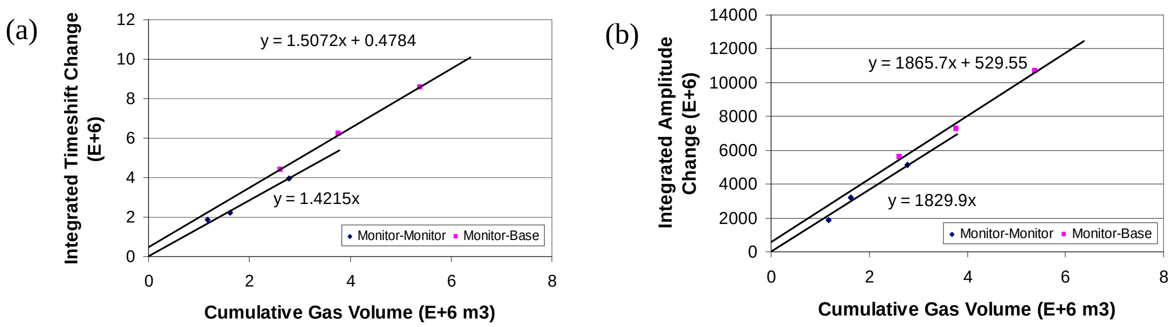

Figure 3 *Total injected gas volume versus: a) integrated time-shift; b) integrated amplitude.*

Discussion

Comparing Figures 4(a) and 4(b), together with their corresponding average and differences, the time-shift and amplitude attributes are observed to generate moderately different gas volume maps. Differences between amplitude and time-delay based interpretations are expected, and are commonly observed. For example Meadows (2008) shows significantly different maps for CO_2 injection into a clastic reservoir, and Tran et al. (2005) show major differences in maps for the injection of a miscible gas and solvent into a carbonate reservoir but conclude that the time-delays appear to agree closer with the well activity. In our example, the two maps do appear to be reasonably close but there are still notable differences. Indeed, both maps possess roughly the same geometric outline consistent with the flow simulation predictions. Both results show an excellent correlation with the known fault system and the edges of the channel to the west and east. Whilst the signals appear to terminate at the fault to the north, there is however a gap between the lowermost edge of the gas volume and the southern fault. The latter observation is explained by structure and gravitational effects using the simulation model. However, it is the fine-scale details between the time-shift and amplitude maps that differ most, with a general mismatch of local highs and lows. As the well injection calibrations using the material balance exercise above are excellent, these differences must be due to the inherent nature of the attributes themselves. One possible reason is that the amplitudes respond to density and velocity, whereas the time-delays respond only to velocity. If density and velocity are uncorrelated, then there will be differences in the attributes. Another reason is that the amplitudes are sensitive to choices made during processing such as the velocity model. There is also some uncertainty in the picks of top reservoir leading to a noisier result as this event does not exhibit a clear peak or trough. Finally, although the amplitudes may be affected differently by variable thin bed tuning effects, preliminary simulator to seismic modelling has shown similar time-shift and amplitude maps and little interference effects. Overall evaluation suggests that amplitude processing may be to blame.

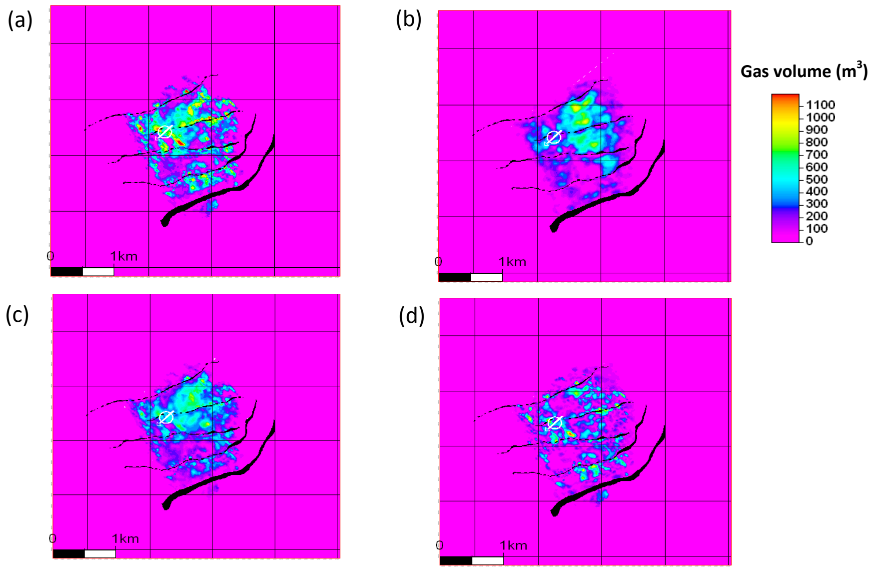

Figure 4 *Gas volume maps (in m^3) for the period up to July 2002, estimated from: a) time shift attributes, b) amplitude attributes. c) The average estimated gas volume map; and d) Differences of the maps.*

Conclusions

An attempt has been made to produce mapped quantitative estimates of gas volume injected into a clastic reservoir. Despite the accuracy of the quantitative calibration using three repeated seismic surveys, time-delay and amplitude attributes reveal fine-scale differences but do show large-scale agreement in the predicted spreads. These differences indicate a disparity in the fundamental nature of the two attributes themselves and highlight the need for a more careful consideration of amplitude processing in the context of 4D seismic data analysis.

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