VSP survey assists in the reservoir characterization of deep-water turbiditic reservoir offshore Brazil

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Abstract

In this case study we review the main results from a rig-source VSP survey, acquired in a deep-water deviated well drilled offshore Brazil. The primary goal for the VSP was to illuminate the lateral variation of thin sand and shale bodies, with higher resolution than available with surface seismic data. This was achieved initially by 2D migration of the VSP data and later, through acoustic impedance inversion of the VSP data.

New surface seismic data is being acquired in the area and the VSP results will be used to quantitatively assess the data processing and the well tie quality. Seismic parameters such as phase, true amplitude and anelastic attenuation are readily available from the VSP measurements. The anelastic attenuation is quite important in this area as the overburden is dominated by highly cyclic siliciclastic deposition, which results in strong attenuation of the seismic data.

Finally, we present some advanced VSP data processing techniques, such as migration of surface related multiples and far field signature estimation for Q-factor computations, which added value to the VSP results.

Introduction

This study concerns a deep-water oil field being developed in the Campos Basin, offshore Brazil. The reservoirs consist of unconsolidated, sand-rich turbidite lobes, dissected by channels. These sand lobes have variable thickness. The surface seismic data acquired in 2000 maps properly the global morphology of these bodies but is not able to resolve thicknesses less than about 30 m (Figures 1 and 2). During 2010, new high-density surface seismic data was acquired to allow better reservoir characterization, aiming to achieve 8-80 Hz bandwidth at the reservoir level (Figure 3). The borehole calibration of the new surface seismic data in terms of phase and amplitude (Morice *et al*., 2003) represented one driver for acquiring a VSP in this field.

Late in 2010, a 37 degrees deviated pilot-hole was drilled to assist landing a horizontal producer well. Underneath the pilot hole, the reservoir sands seemed to terminate but the limited surface seismic resolution, about 30 m for a frequency content of 10-45 Hz, could not image the stratigraphic details (Figures 1 and 2). A rig source VSP was run in the pilot-hole to better illuminate that part of the reservoir, with high-resolution 2D seismic images, accurately tied to the well, in time and in depth.

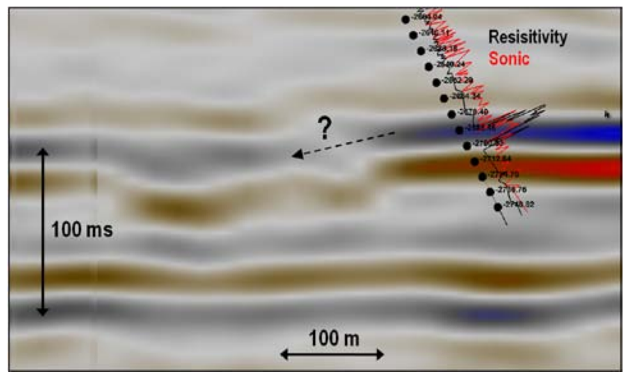

Fig. 1. PSTM surface seismic line extracted along the well path. The lateral extension of the high amplitude sand body is not clearly defined. The frequency content at the reservoir level is approximately 10-46 Hz. The time thickness of the reservoir (blue trough to red peak) is overestimated by a factor of two. Negative amplitude in blue corresponds to acoustic impedance decreases.

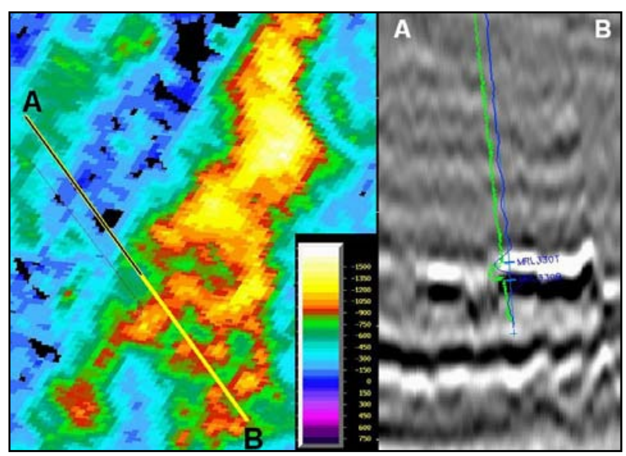

Fig. 2. Amplitude map for the top of reservoir (negative amplitude) with seismic section taken along the well trajectory (well is in black on the left panel). On the right panel the density log is shown in green and the synthetic seismogram in blue.

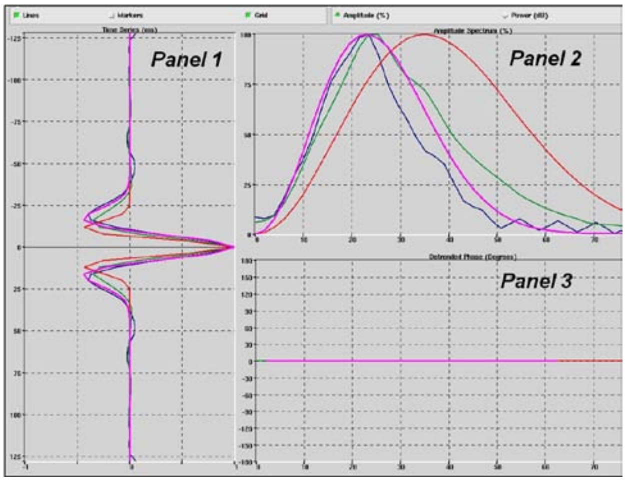

Fig. 3. Wavelets extracted at the reservoir level for the seismic data acquired in 2000 (blue) and for the fast track processing of the 2010 data (green). A 23 Hz Ricker wavelet (pink) is closer to the existing data bandwidth than the 35 Hz Ricker wavelet (red). The latter wavelet is expected to match the final results of the 2010 data being processed.

Method

For the VSP acquisition, a four-level tool was used with 15 m spacing, fitted with tri-axial accelerometer sensors. These sensors are omni-tilt, non-gimbaled, having a flat amplitude response from 3 to 200 Hz, and a linear phase response over the same interval. A triple Sodera G-Gun airgun array, with three 250 cu.in., was deployed with buoys from a semi-submersible's crane at 5.5 m depth, with 57 m offset from the wellhead and fired at 2000 psi. The guns were automatically tuned with an insea gun controller, which recorded also for every shot, the near field signatures, gun pressure and gun depth.

Seventy seven VSP levels were acquired every 15 m to cover the deviated well trajectory, together with three Checkshots acquired up to the sea floor for velocity control. The VSP data showed wide frequency content at well TD, with useable frequencies from 5 to 96 Hz.

The data was processed to produce high-resolution time and depth migrated 2D images underneath the well path. The data processing steps included 3-component data rotation to vertical and inline and crossline directions, wavefield separation, deterministic deconvolution of upgoing by downgoing waves, 2D velocity model calibration using direct P-wave tomography and Generalized Radon Transform (GRT) to perform 2D depth migration of the data (Miller *et al*., 1987).

The surface related multiples recorded as downgoing waves, were also migrated to produce an image above the receivers, up to the sea floor. The simple method used, called mirror imaging, is described in Schlumberger internal communication (Michael Sanders, 2004) and it is illustrated in Figure 10. The GRT migration algorithm was used to migrate the surface multiples.

The anelastic seismic attenuation was computed from the VSP data over two main intervals: (i) from the sea floor to the top of the cyclic deposition interval (about 800 m thick) and (ii) over the cyclic deposition interval (about 1000 m thick). For the VSP interval, the separation of the downgoing waves was performed, followed by predictive deconvolution with a gap of three zero-crossings of the autocorrelation function. This preserves the first arrival pulse, eliminating the oscillations of the bubble and downgoing multiples, resulting in frequency spectra less affected by spectral notches. This last point is important because the method for estimating the Q factor used is the spectral ratio method (White, 1992). This method assumes in particular that the source signature does not vary, that the geophone coupling does not vary and that the pulse being analyzed suffers only intrinsic constant Q effects. The last condition is often not met and in general we estimate effective Q values. The method of Ziolkowski *et al*. (1982) was used to estimate the far field source signature at the sea floor from the high-fidelity near field source signature measurements (Figure 4). The far field signature estimated was converted to the acceleration domain in order to be compared to the VSP accelerometer data.

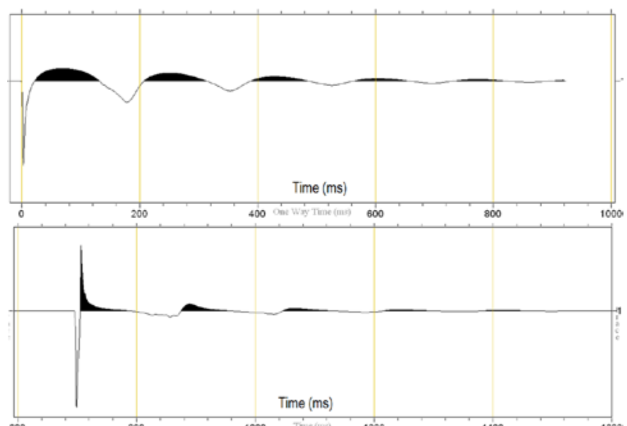

Fig. 4. Near field source signatures (top) were measured for every shot and the corresponding far field signatures were estimated (bottom). The near field hydrophone is located 1.25 m away from the airgun cluster centroid.

Results

Synthetic seismograms were generated from sonic and density logs, after calibration with the VSP times. The high-resolution VSP migrated images (5-96 Hz) were first compared to high-resolution synthetics. The tie between both datasets is excellent (Figure 5).

The depth migrated VSP image shows enhanced vertical resolution compared to surface seismic (Figures 1 and 8), allowing mapping the 15 m thick reservoir sand lobe and its thinning out away from the well (Figures 6 and 7). The VSP data is true amplitude, zero-phase and perfectly tied in depth and in time.

Attenuation Q-factors were estimated from the VSP data and a good fit was obtained in the spectral domain

(Figure 9). An effective Q of 150 was estimated for the 800 m interval below sea floor and an effective Q of 45 was determined for the 1000 m thick cyclic interval above the reservoir. This low Q value explains the low frequency content of the surface seismic data at the reservoir level, despite of the large water column and small burial depth.

The migrated image of the surface related multiples ties very well with the surface seismic primaries (Figure 10), validating the mirror imaging technique and its ability to extend the standard VSP images above the downhole receivers in deep-water VSP surveys. Despite the three-way time trajectories in the VSP mirror image, the frequency content is equivalent to the surface seismic data, which is only two-way-time.

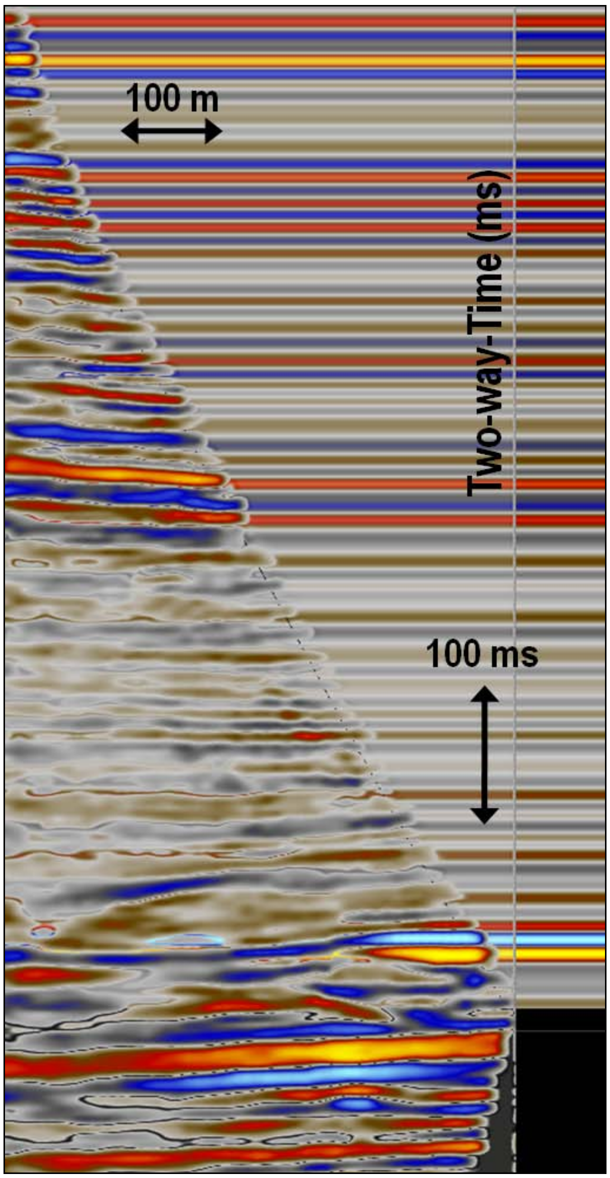

Fig. 5. VSP migrated image displayed in time on top of a 1D synthetic seismogram (shown as a 2D section for visualization purposes). The bandwidth of both datasets is 5-96 Hz. Negative amplitude in blue corresponds to acoustic impedance decreases.

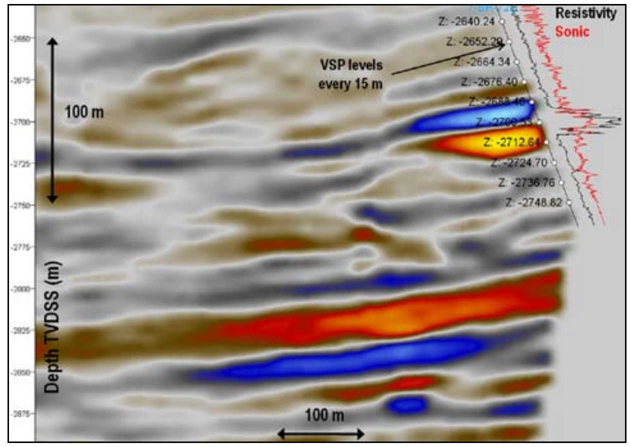

Fig. 6. Depth migrated VSP image with the vertical scale slightly exaggerated. The VSP resolves the 15 m thick reservoir sands and maps their thinning-out away from the well. Negative amplitude in blue corresponds to acoustic impedance decreases.

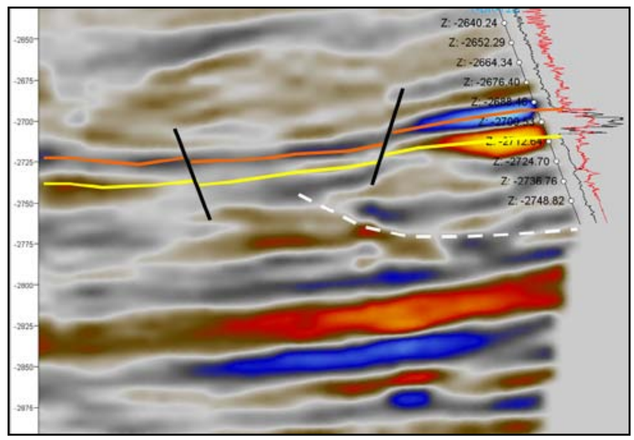

Fig. 7. Seismic interpretation of the VSP image in previous figure, showing small throw faults (black), local erosion (white) and top and base of reservoir (orange and yellow).

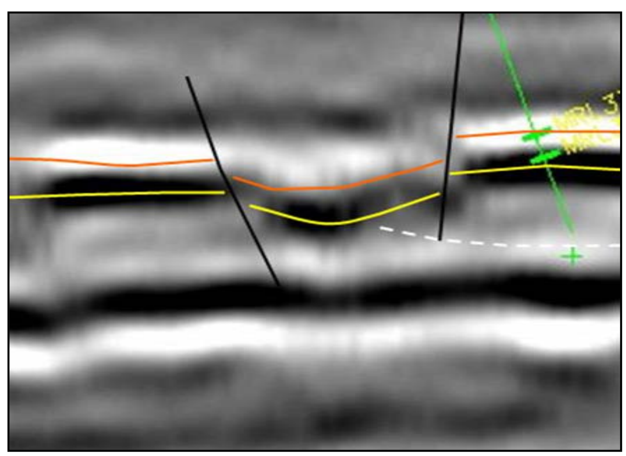

Fig. 8. Surface seismic data acquired in 2000 with the VSP interpretation from figure 7 superimposed (schematic only).

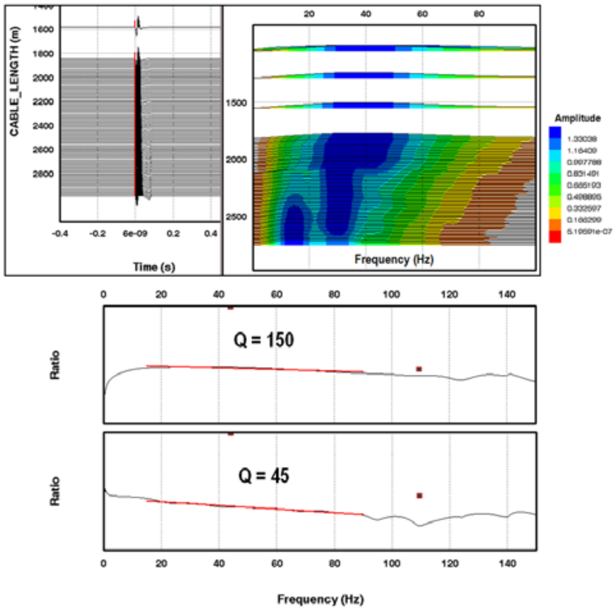

Fig. 9. Q-factor estimation using the spectral ratio method, for the two main intervals described in the text. The low effective Q of 45 is due to stratigraphic filtering (cyclic deposition).

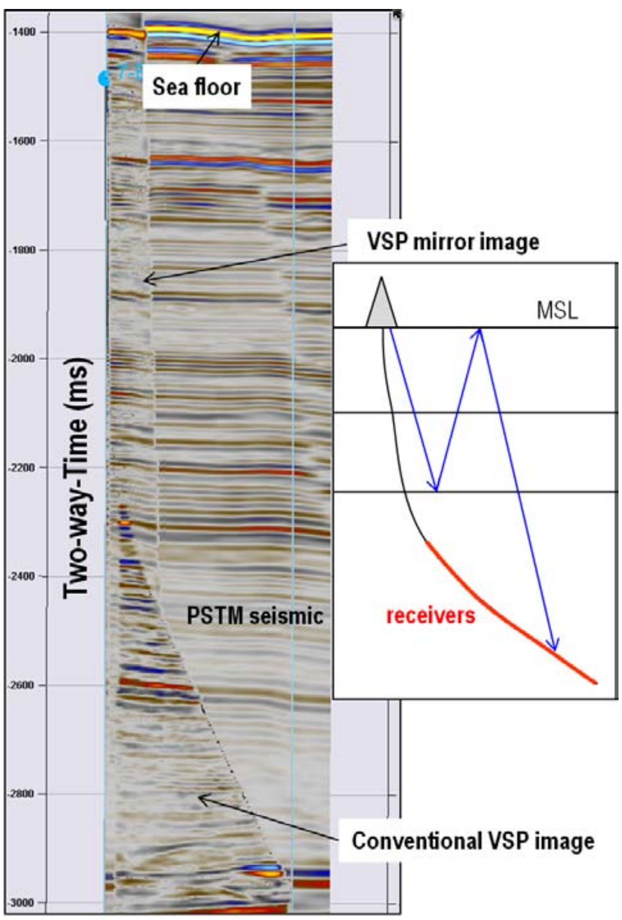

Fig. 10. Conventional VSP image and VSP mirror image of surface related multiples, both overlaid on PSTM surface seismic line passing through the well. Negative amplitude in blue corresponds to acoustic impedance decreases.

Conclusions

The VSP tie to the surface seismic and synthetics was considered very good. The high-resolution 2D VSP images allowed mapping the top and base of the main reservoir sand penetrated by the pilot-hole, 15 m thick, as well as its thinning-out away from the well, unveiling stratigraphic details not visible in the surface seismic data. This geological setting could be, therefore, a good candidate for 3D-VSP imaging.

The anelastic attenuation in the area was characterized using the VSP data and two very distinct effective Q-factors could be determined. A high Q of 150 was found in an interval below the sea floor, and a low Q of 45 (high attenuation) was determined in the thick cyclic siliciclastic deposition interval above the reservoir.

The surface seismic data acquired in 2000 had a bandwidth of 10-45 Hz at the reservoir level, while the VSP images reached 5-96Hz. The new data acquired in 2010 aims at a achieving a wider bandwidth and the Q values estimated from the VSP will be used in the data processing.

Finally, by using the deep-water surface related multiples and the mirror imaging technique, the VSP image could be extended successfully above the geophones up to the sea floor, with a good match with the surface seismic.

Acknowledgments

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