3D VSP in the deep water Gulf of Mexico fills in subsalt ‘shadow zone’

Brian E. Hornby, John A. Sharp, John Farrelly, Stephen Hall, and Hans Sugianto*

Introduction
One of the biggest challenges that exists for seismic imaging is subsalt. In the Mad Dog field, a complex salt body creates illumination problems with surface seismic imaging, resulting in ‘shadow zones’ where the surface seismic is blind to areas of subsalt structure. Figure 1 is a representative seismic section. Here the red line indicates the area around the crest of the structure that is poorly imaged by surface seismic. For subsalt imaging - it is well known that the salt geometry will strongly affect whether or not seismic signals can pass through the salt twice and so potentially be recorded at the surface and used to image the subsurface.

A dipping base of salt has a strong effect here - as the dip of the base of salt increases beyond the critical angle no rays transmit through the top of salt twice and so will not be received by surface seismic acquisition systems (Muerdter et al., 2001). In this case one possibility to fill in these illumination holes is to place the receivers below the salt, resulting in only one travel path through the salt. In this paper we look at the use of 3D VSP using geophones placed below the obscuring salt to image structure at Mad Dog where the surface seismic is blind.

3D VSP acquisition
Figure 2 represents a 3D VSP survey. We have receivers in the borehole and an areal grid of surface sources obtained using a seismic shooting vessel as shown in Figure 5. Signals reflected off subsurface structure are acquired by the downhole array and migrated using a prestack depth migration algorithm to create a 3D image volume around the wellbore. A major innovation in this project is the concept and implementation of blue-water deployed ‘rig-less’ or off-line VSP acquisition for a single derrick-drilling rig (Figure 3). Off-line acquisition had previously been implemented at Thunder Horse using a dual-derrick rig (Ray et al., 2003).

Because of the long time required for the 3D VSP surveys (up to two weeks) substantial rig savings are possible by taking the VSP acquisition totally off-line. In Figure 3 we see the development of the implementation of off-line ‘rig-less’ VSP acquisition. The left picture shows the implementation for the first well - here the platform for the false rotary table is positioned outside the railing and, for the second well, the assembly was moved to another vessel where we could position the platform within the railing. In Figure 4 we see the ‘blue water’ deployment into the wellhead at a water depth of 1350 m. The left section shows the ROV stabbing the tool into the wellhead, the

*BP America, 501 WestLake Park Boulevard, Houston, TX 77079.

Figure 1 Pre-stack depth migrated seismic section showing complicated salt body and poor imaging area (red line).

Figure 2 Representation of a 3D VSP imaging survey.
Implementation of off-line acquisition for a single derrick-drilling rig required successful completion of a large technical and health safety and environment (HSE) evaluation and involved cooperation among the drilling and VSP contractors, and BP's drilling, subsurface, and exploration and production technology team members.

Additional cost savings were obtained by configuring multi-source seismic source boats together with new down-hole technology to implement large seismic arrays. For the first survey a dual source seismic vessel was implemented and for the second survey a three-source array was implemented (Figure 5). A spiral geometry was chosen as the most efficient shot geometry (Figure 5).

For Mad Dog, a modelling study conducted in 2002 determined that, for a given number of receivers, the best images result from a receiver array as large as possible while honouring aliasing criteria (Van Gestel et al., 2003). In that study best results were seen with receiver arrays greater than 500 m or so in length. And so in planning for this survey we focused on the largest array we could practically deploy with 30.5 m spacing between levels. In the first well we were able to deploy a total array length of 730 m using 25 levels and on the second well we used a total array length of 580 m using 20 levels.

**Wellsite processing of walkaway surveys**

Critical parameters for the surface source deployment are the radial extent of the spiral survey and the distance between spiral arms. Both of these parameters affect total
Figure 5  Actual spiral shot pattern using seismic shooting vessel with three source arrays.

Figure 6  Walkaway images, processed using wave-equation pre-stack depth migration techniques, for all 25 levels.

Figure 7  Processing of walkaway VSP data to determine maximum source offset.
survey time and hence the cost. Initial parameters for the survey are first estimated by a numerical modelling and migration exercise (Van Gestel et al., 2003). At the wellsite, test walkaway surveys were first acquired and then the 3D VSP survey is started using the pre-determined parameters. In parallel, the test 2D walkaway data are processed to 1) determine final parameters for the 3D VSP survey, and 2) get a first look at the imaging prize.

In Figure 6 we examine the effect of the shot spacing on the image. Here we want to use as large a spacing as we can without any appreciable image degradation. In Figure 6 we see walkaway images, processed using wave-equation pre-stack depth migration techniques, for all 25 levels. First, for the ‘all data’ picture, it is apparent that we are achieving our goal of imaging the important SE dipping structure (circled elements). Going to 21.5 m spacing we see some degradation of the image but it is still acceptable. However, at 340 m spacing, it is clear that the spacing is too large - the image quality has degraded significantly and migration artifacts are noticeably stronger. For this survey a 100 m shot spacing was used, which was the largest spacing the seismic shooting vessel allowed. This spacing put us well in the best image area.

The next parameter to examine is the maximum radius of the survey. In Figure 7 we show test processing results for three survey offsets - 6 km, 9 km, and 10 km. Again, key structural elements are circled. It is apparent that the 6 km offset survey will not result in usable images of the target features and more than 9 km offset is required to get good images of these features. After additional imaging tests at finer scale it was decided to use a maximum offset of 9½ km.

Actual 3D data taken in the first survey were 38,000 shots into 25 3C levels, for a total of 2.85 million traces. To the best of our knowledge this was the largest 3D VSP survey ever acquired in a single well. Other records at the time of the survey: longest wireline deployed tool in a well (750 m) and longest wireline deployed geophone array in a well (730 m).

3D processing

Processing flows for the 3D data are detailed in Shoshitaishvili et al. (2004) and Clarke et al. (2004). Processing consists of seven major steps: data loading and quality control, data editing and filtering, vector fidelity correction, up- and down-going wave separation, zero-phasing, vector migration, and post-migration processing. The vector migration process involves migrating each of the three components of the data separately using shot-record migration and then combining the images by projecting the three components at each image point onto the vector pointing from the image point to the receiver (Shoshitaishvili et al., 2004). The result is a single image using the optimal P-wave reflection data.

Results

Figure 8 shows a comparison between the 3D VSP and the surface seismic for the first well. Here the top picture is the...
seismic image showing an imaging hole under salt (yellow box) and the bottom picture is an overlay of the 3D VSP section with the surface seismic showing images of the dipping structure along with indications of sub-seismic scale faulting with a throw of around 60 m. In Figure 9 we see a plot of a section of the surface seismic around the location of the second well the 3D VSP was run in. Here the reliable seismic image stops some distance from the planned wellbore. The objectives are to penetrate producing intervals near the crest of the structure. Figure 10 shows the results for the red box area in Figure 9. The surface seismic (left - zoomed section from Figure 9) gives us no information of the structure in this critical section.

On the 3D VSP image (right side) we see the reservoir imaged (yellow line), and the brown line is an apparent image of the fault. What happened here was a fault of approximately 500 m throw was encountered causing the first well to miss the pay entirely. The second well penetrated a small piece of the pay, but not enough. The third well hit the pay in the right place.

Confirmation of the location of the fault and reservoir was determined using wellbore information, with the blue lines indicating the dipmeter determined interpretation of fault location and direction in the three wells and the location of the reservoir confirmed by penetrations of the second and third wells.

What is the value of a VSP now that the VSP has been run in the third well? If we had acquired the 3D VSP survey in a nearby well before the first well we could have saved two sidetrack wells. If we had acquired it in the first wellbore, we could have saved one sidetrack well. So, potentially major savings and risk reduction were possible using a 3D VSP in this case.

Conclusions

3D VSP is shown to be a powerful tool to fill in surface seismic ‘no-data’ areas for subsalt reservoirs. With two wells acquired in the Mad Dog field we were able to see in the first case structure and sub-seismic scale faulting not seen by the surface seismic, and in the second case an image of both the reservoir and a large fault not seen by the surface seismic. In the second case, it was determined that two sidetrack wells could potentially have been saved if the 3D VSP was acquired before the first well. Successful

![Figure 10 Results from the second 3D VSP survey. The surface seismic (left - zoomed section from Figure 9) gives us no information of the structure in this critical section. On the right side on the 3D VSP image we see the reservoir imaged (yellow line), and the brown line is an apparent image of the fault. What happened here was a fault of approximately 500m throw was encountered causing the first well to miss the pay entirely. The second well got a small piece of the pay, but not enough. The third well hit the pay in the right place. Confirmation of the location of the fault and reservoir was determined using wellbore information, with the blue lines indicating the dipmeter determined interpretation of fault location and direction in the three wells and the location of the reservoir confirmed by penetrations of the second and third wells.](image-url)
implementation of ‘rig-less’ off-line acquisition and walk-away imaging tests at the wellsite were key to the success of this project.

Acknowledgements
The authors wish to thank BP and partners Unocal and BHPB Billiton for their support and permission to present this work. In particular, we wish to thank Mad Dog drilling team members, Murry Sepulvado, Doug Hill, Rusty Cook, Perry Hill, and Harry Prewett. Read Well Services and Schlumberger provided VSP services for the two surveys. GX Technologies provided seismic source boat services for the first survey and Western-Geco provided seismic source boat services for the second survey. Internav provided navigation services for the first survey and Oceaneering provided ROV technology for both surveys. PGS Marine Geophysical provided the 3D seismic data used for the seismic imaging results. Computing support and resources were provided by BP’s High Performance Computing Center team.

References


Ray, A., Hornby, B., and Gestel, J., 2003, Largest 3D VSP in the deep water of the gulf of Mexico to provide improved imaging in the thunder horse south field. 73rd SEG Annual International Meeting, 422–425.
