VSP: Beyond time-to-depth

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VSP or vertical seismic profile was originally designed and is currently primarily used to give us time-to-depth for seismic-well ties. Beyond time-to-depth a number of possibilities exist. Recently, there has been considerable interest in VSP imaging (Ray et al., 2003; Paulsson et al., 2004; Hornby et al., 2004; Hornby et al., 2005a), with extensive surveys being acquired both on land and offshore. Modeling studies using full-waveform finite-difference method (FDM) (Payne et al., 1994; Van Gestel et al., 2003) show us what we can image for a particular acquisition geometry and geology, with best image results seen with 3D VSP surveys incorporating a large VSP array in the well and a 2D source pattern acquired using a surface seismic shooting vessel. Traditionally, VSP imaging has been implemented using surface seismic processing algorithms. However, the VSP geometry poses its own challenges and unique opportunities. In this article we explore some imaging methods to attempt to take advantage of the VSP geometry. In addition we discuss the use of permanent in-well seismic sensors for reservoir monitoring.

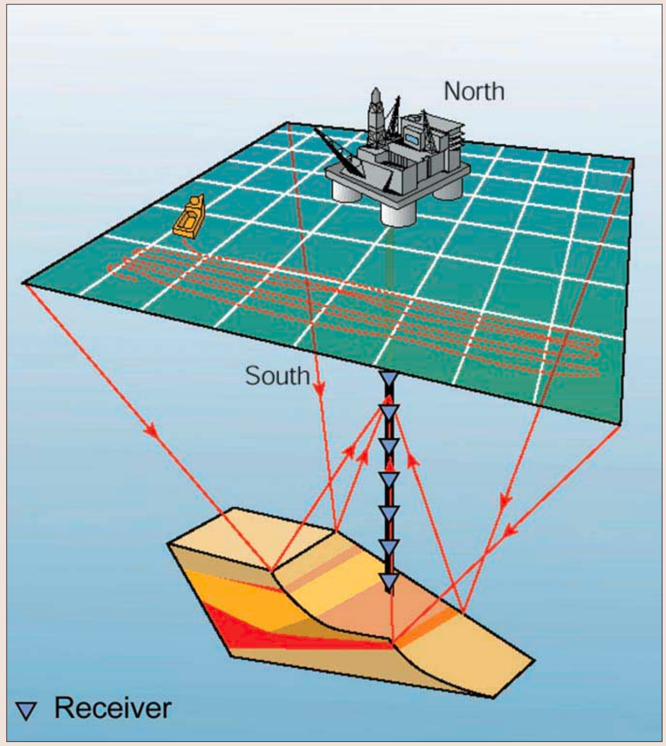


Figure 1. Representation of a 3D VSP imaging survey.

3D VSP imaging. Figure 1 represents a 3D VSP survey. We have receivers in the borehole and a 2D surface source geometry using a seismic shooting vessel. Signals reflected from subsurface structure are acquired by the downhole array and typically migrated using a prestack depth-migration algorithm to create a 3D image volume around the wellbore.

Technical goals are to complement surface seismic with (1) improved resolution, improved image quality and better high-dip structure definition (e.g., salt flanks), and (2) fill in "image holes" in complex subsalt or other plays where surface seismic is blind.

Business drivers are to:

1) reduce risk in well placement
2) improve reserve calculation
3) understand compartmentalization and stratigraphic variation

Now before a survey is undertaken, a few questions have to be answered. What is the potential imaging prize and does that meet with our expectations? If so, what survey is required to achieve that prize? What are the trade-offs in survey parameters and results (e.g., sensors deployed all through the well versus lower-cost limited array)?

3D FDM modeling feasibility planning. 3D finite-difference method (FDM) modeling can be used to answer these and other questions. Figures 2 and 3 show an example of the results of a 3D FDM modeling study. The goal of this study was to do a 2D walkaway survey to verify the structure along the dip line. However, the 3D nature of the salt was a concern and so it was decided to do a 3D FDM study to examine if a 2D survey is possible. Velocity and density models are in Figure 2, and results of the modeling study, zoomed in on the windowed region, are shown in Figure 3. Looking at the 2D walkaway results in Figure 3 we see that the 2D walkaway image poorly images the structure represented by the density survey; the image is distorted, and dip of the structure is wrong. The 3D VSP result, however, shows a good image of the structure, leading us to conclude that the 2D approximation falls apart for this case. The result for this example is that,

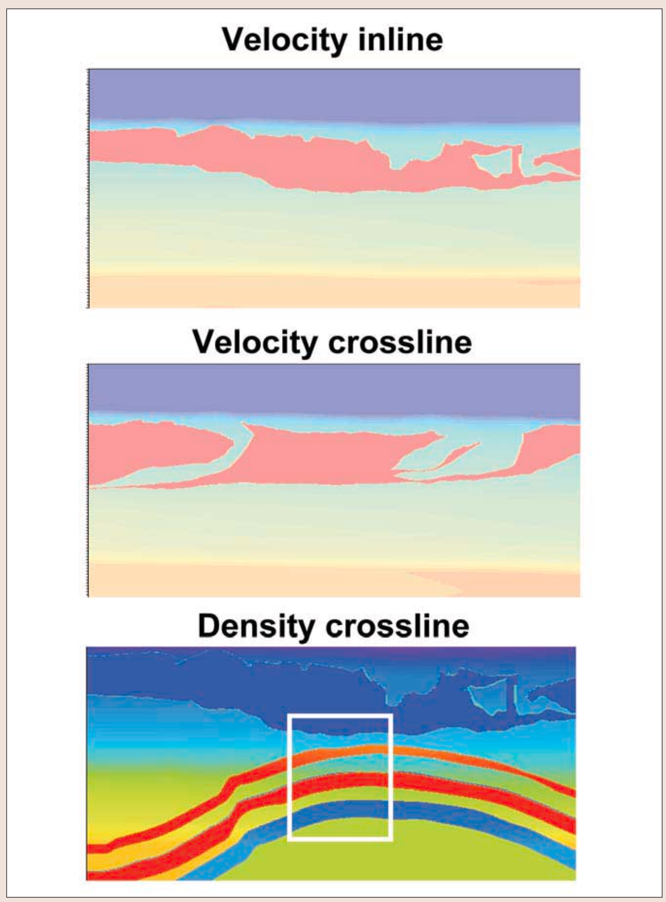


Figure 2. Velocity and density models for 3D FDM study.

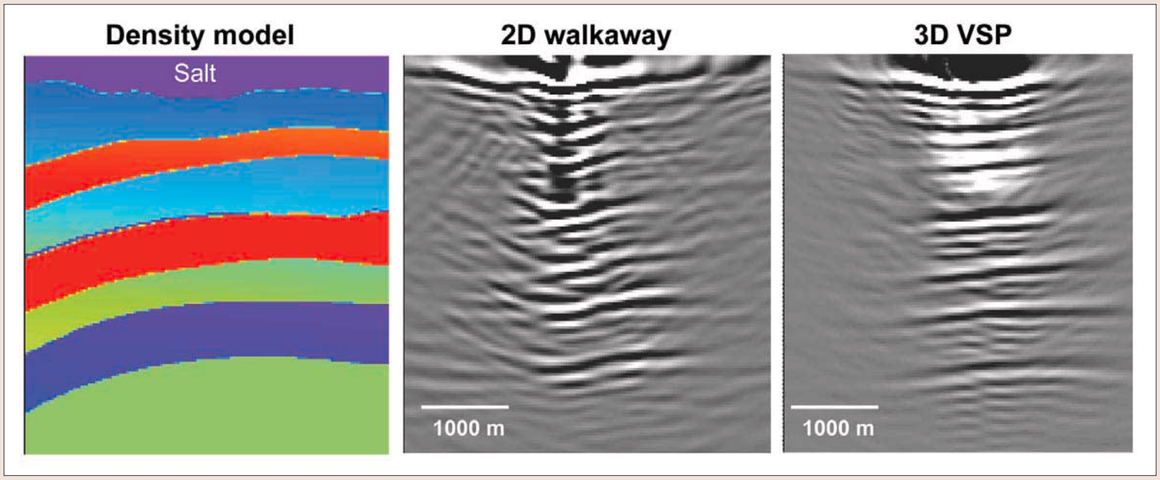


Figure 3. 3D FDM study results over the windowed region in Figure 2. For this complicated salt structure, clearly a walkaway survey will not achieve the goal of imaging in the crossline direction and a full 3D VSP survey is required.

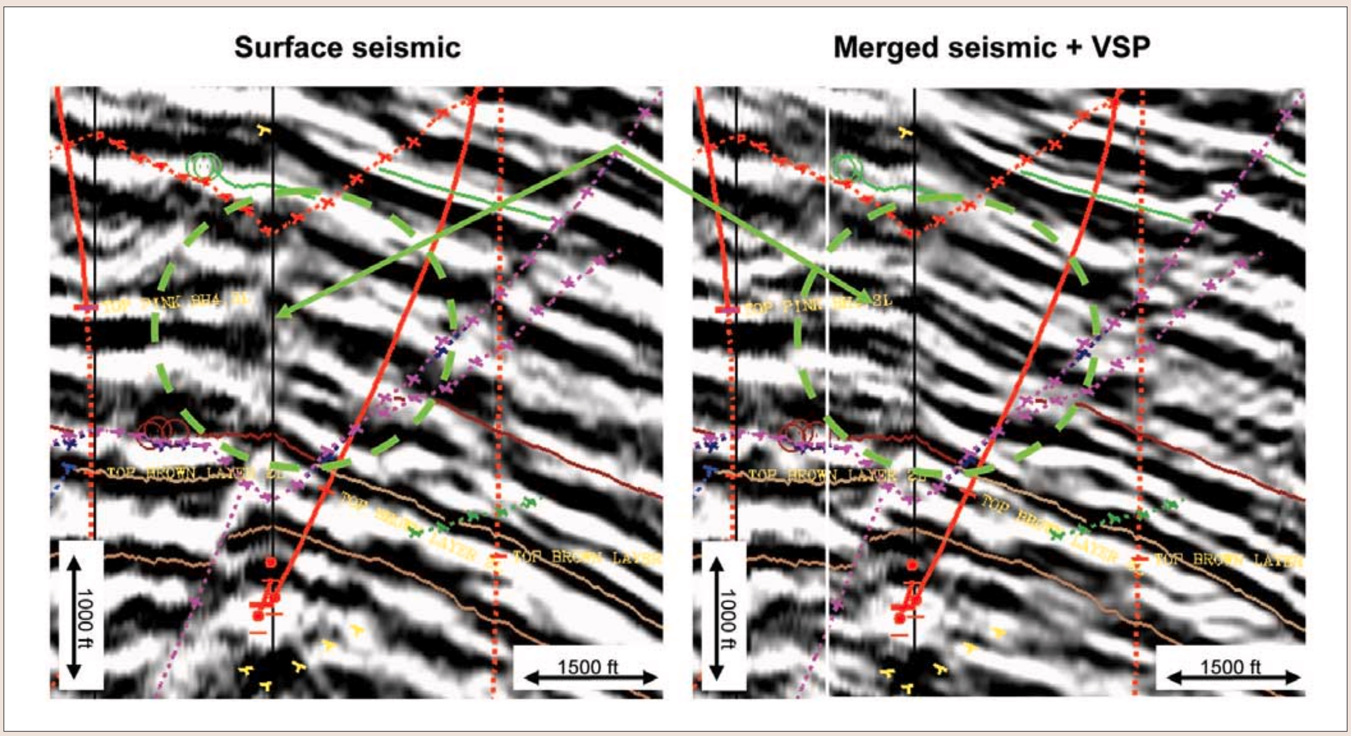


Figure 4. High-resolution imaging example. Overall the merged 3D VSP shows higher vertical resolution than the surface seismic. Highlighted section is a reservoir sand that was penetrated by a recent sidetrack well (solid red line). Original surface seismic (left) suggested that the reservoir sand may be faulted out (left arrow) close to the proposed sidetrack well, risking an objective for this well. Bringing the 3D VSP image on board (right) shows a crisper image of the interval and indicates that the reservoir does continue across the track of the well (right arrow). Based on this new interpretation the well was drilled and penetrated the reservoir sand as predicted by the VSP interpretation.

in order to image the structure of interest, we either have to acquire a 3D VSP survey or nothing! 3D FDM modeling is a recommended first step before all VSP imaging surveys, including 2D walkaway surveys.

3D VSP imaging examples. 3D VSP imaging surveys were processed using wave-equation method (WEM) prestack depth-migration (PSDM) techniques. Figure 4 is a high-resolution example. In this area we have good surface seismic but we still get surprises in new wells due to subseismic scale faulting and other features. Here the VSP is merged with the seismic to come up with the optimal image (Ray et al., 2005). Overall the merged 3D VSP shows higher vertical resolution than the surface seismic. Highlighted section is a reservoir sand that was penetrated by a recent sidetrack well (solid red line). Original surface seismic (left) suggested that the reservoir sand may be faulted out (left arrow) close to the proposed sidetrack well, risking an objective for this well. Bringing the 3D VSP image on board (right) shows a crisper image of the interval and indicates that the reservoir does continue across the track of the well (right arrow). Based on this new interpretation the well was drilled and penetrated the reservoir sand as predicted by the VSP interpretation.

Figure 5 shows a subsalt imaging example. It is quite common in the deepwater Gulf of Mexico to have illumination holes below complex salt—in this case the crest of the structure through which we are drilling the wells is not imaged. A 3D VSP survey with the geophones placed below salt can get around this problem. 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 1500-ft 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. The location of the fault and reservoir was confirmed using wellbore information, with the blue lines indi-

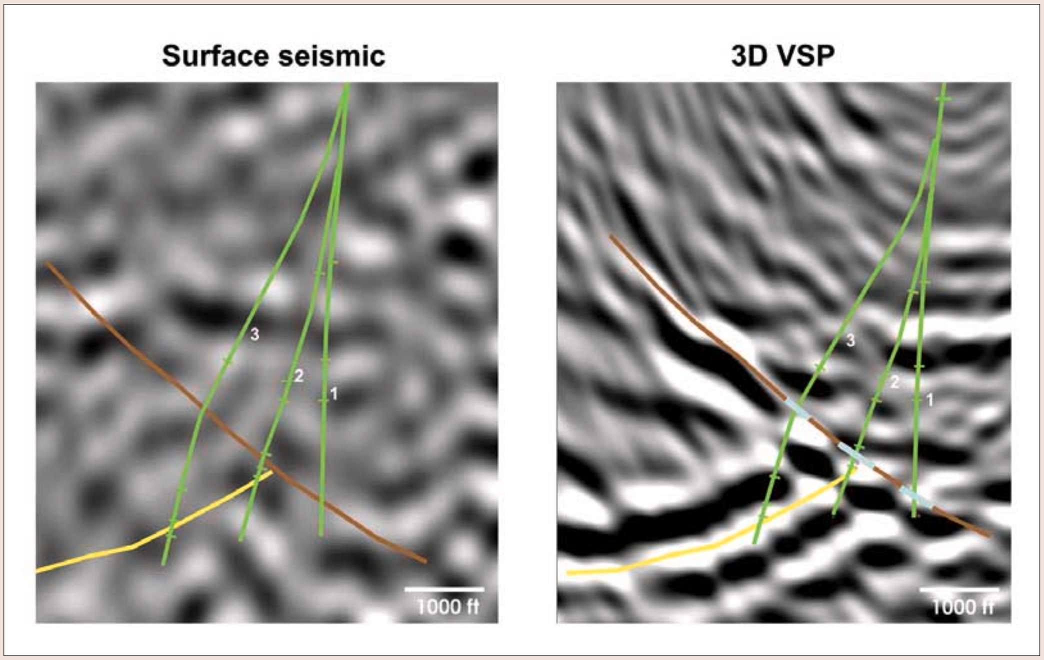


Figure 5. A subsalt imaging example. It is quite common in the deepwater Gulf of Mexico to have illumination holes below complex salt—in this case the crest of the structure through which we are drilling the wells is not imaged. A 3D VSP survey with the geophones placed below salt can get around this problem. 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 1500-ft 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. The location of the fault and reservoir was confirmed using wellbore information.

cating the dipmeter determined interpretation of fault location and direction in the three wells. What is the value of a VSP? Now the VSP was run in the third well—if we had acquired the 3D VSP survey 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 could have been realized using a 3D VSP in this case.

Imaging with multiples. A recent advance in imaging algorithms for VSP is imaging with multiples (Jiang et al., 2005). The principle of surface-related multiple migration is shown in Figure 6. Here the idea is to image using the first down-going ghost. The raypath for a primary arrival is the blue line and raypath for the multiple arrival (first down-going ghost) is the red line. Multiples clearly have different fold and coverage than the primaries. An example of imaging using multiples is shown in Figure 7. The top shows migration images obtained by migrating ghosts in 3D VSP marine data. The bottom shows primary reflections in 3D CDP data over the same area. The VSP image shows higher-resolution imaging of comparable features and is imaging a record 40 000-ft section.

A subsalt multiple imaging example is shown in Figure 8. The VSP multiple image sees the sea bottom, top and base of salt, (arrows) and where the surface seismic images well (upper subsalt section) sees similar bedding features and dips. Where we see only hints of structure on the surface seismic (middle subsalt section), we see better images on the VSP multiple image, and also we see structure imaged on the VSP multiple image below the image area of the surface seismic (lower subsalt section).

The VSP primary image has trouble with noise near the wellbore but does add to the picture with faint imaging of structure dipping to the southeast that ties in with the surface seismic (arrows). So clearly the VSP multiple image adds additional information that compliments both the surface seismic and the VSP primary imaging results.

Salt flank imaging using interferometry. VSP has long been a tool for investigating the location of salt flanks. Traditionally a salt proximity survey has been used to estimate the location of salt boundaries relative to a wellbore. However, this technique depends on accurate knowledge of the shape of the salt

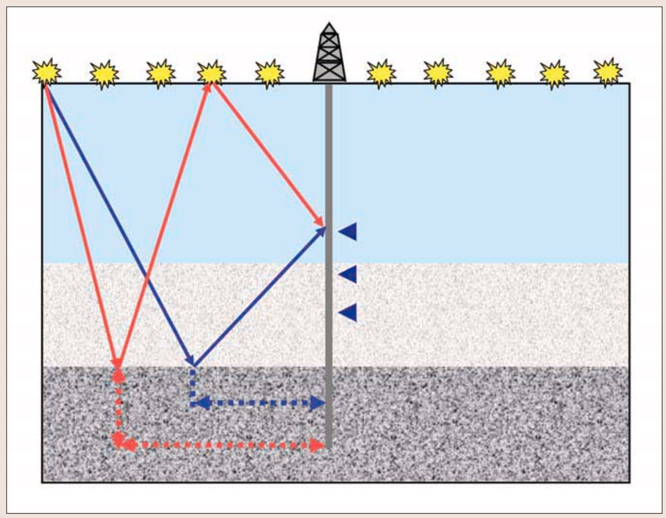
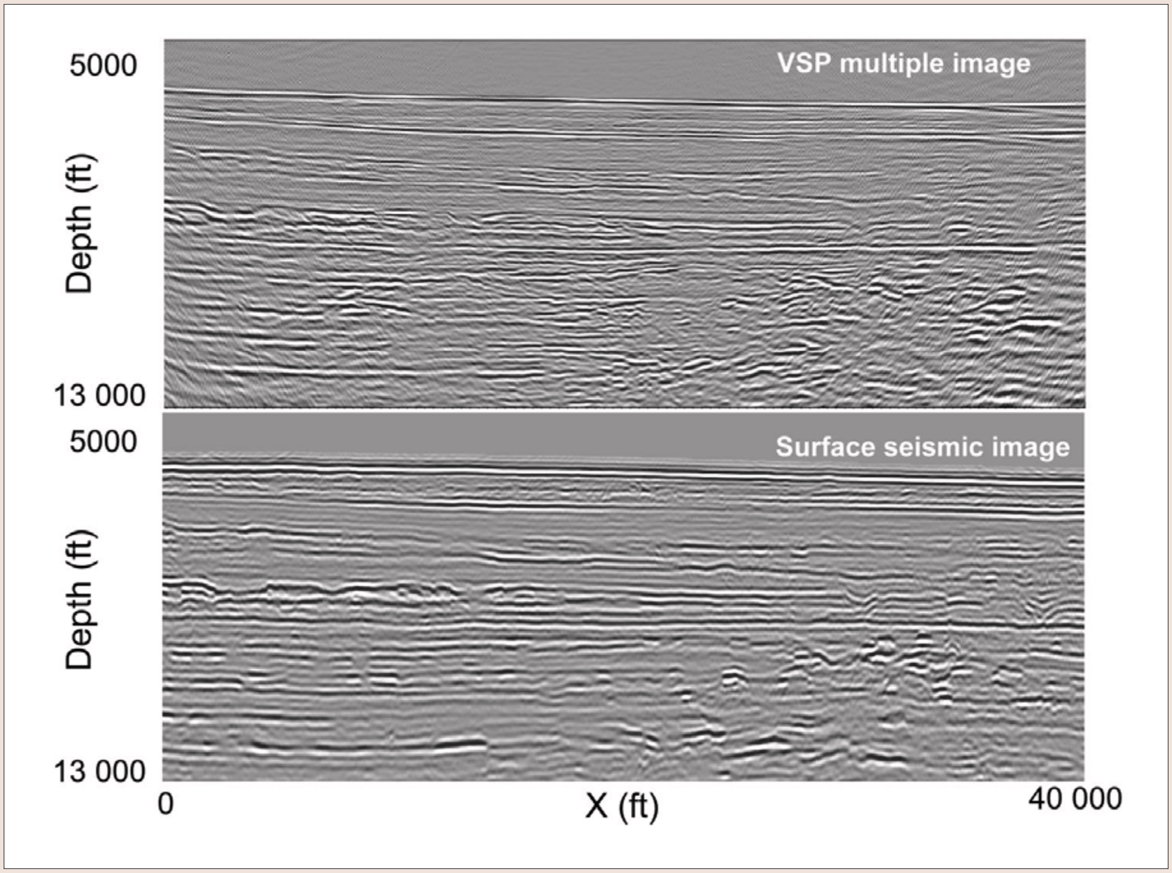


Figure 6. Imaging with multiples. Raypath for a primary arrival is the blue line, and raypath for the multiple arrival (first down-going ghost) is the red line. Multiples clearly have different fold and coverage than the primaries.

and on knowledge of the local sediment velocities. Many researchers have developed various migration methods and strategy for the purpose of improving the imaging of salt flanks. Recently, Brandsberg-Dahl et al. (2003) imaged a vertical salt boundary using walkaway VSP data by using sideways imaging method. Another possibility is to use interferometry to redatum the surface sources to the receiver array. With this method one need not have any knowledge of the overburden or salt structure. The basic idea behind seismic interferometry is related to the early work of Claerbout (1968) who suggested that surface noise could be used to image the subsurface structure by using correlograms, even though the source wavelet and location were unknown. In recent years, interferometry has attracted a lot of attention for imaging using passive seismic data (Draganov et al., 2004; Schuster et al., 2004; Wapenaar et al., 2005). Recently, Calvert and Bakulin (2004) applied interferometry for time-lapse VSP imaging of a reservoir. Their technique involved instrumenting a deviated borehole with geophones, and then using interferometry to convert surface-to-borehole (VSP) data into a

Figure 7. Migration images obtained by migrating (top) ghosts in 3D VSP marine data and (bottom) primary reflections in 3D CDP data over the same area (Jiang et al., 2005). The VSP image shows higher-resolution imaging of comparable features and is imaging a section with a length of 40 000 ft.



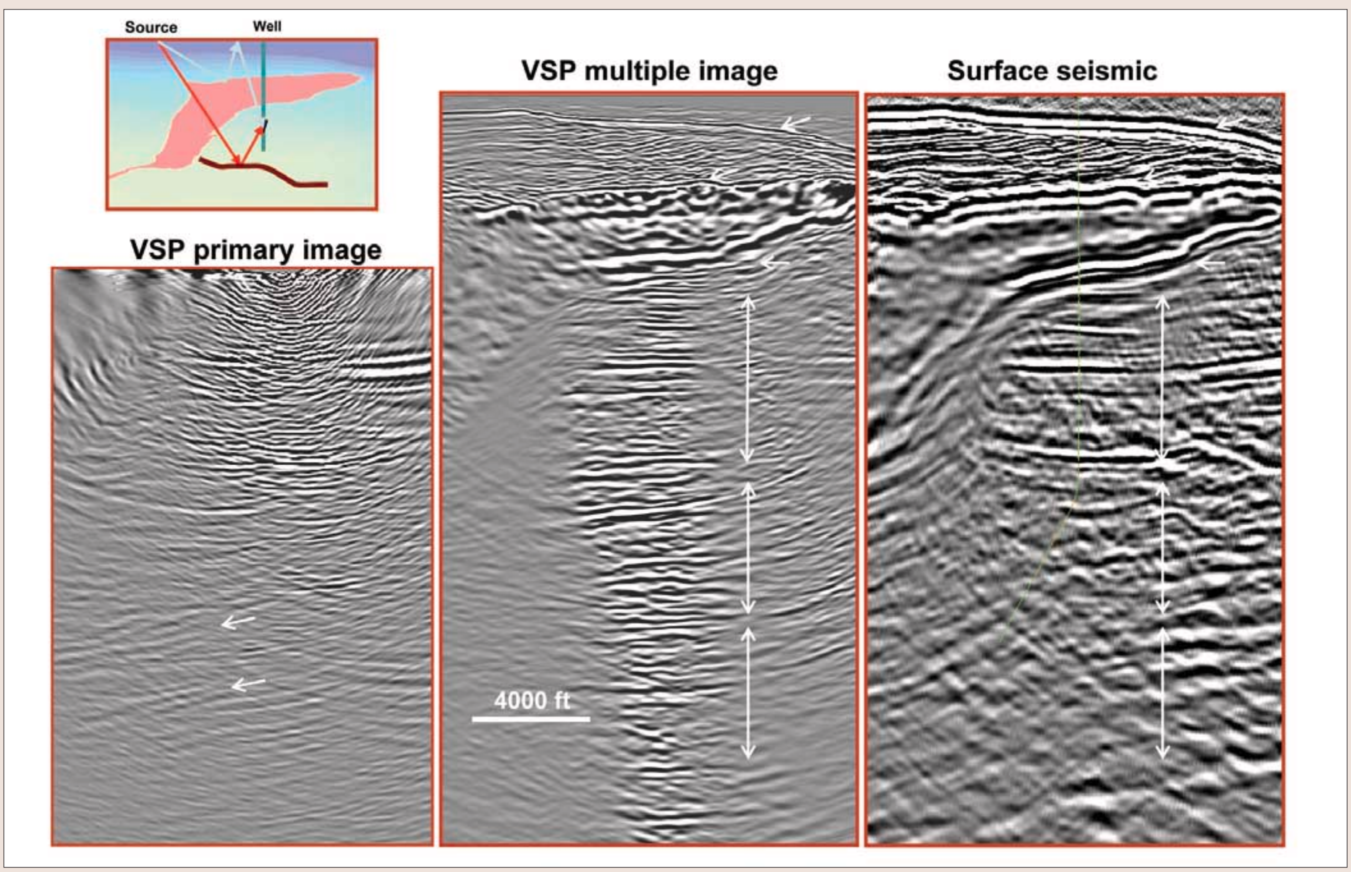


Figure 8. Subsalt multiple imaging example. The VSP multiple image sees the sea bottom, top and base of salt, (arrows) and where the surface seismic images well (upper subsalt section) sees similar bedding features and dips. Where we see just hints of structure on the surface seismic (middle subsalt section), we see better images on the VSP multiple image, and also we see structure imaged on the VSP multiple image below the image area of the surface seismic (lower subsalt section). The VSP primary image has trouble with noise near the wellbore, but does add to the picture with faint imaging of structure dipping to the southeast that ties in with the surface seismic (arrows).

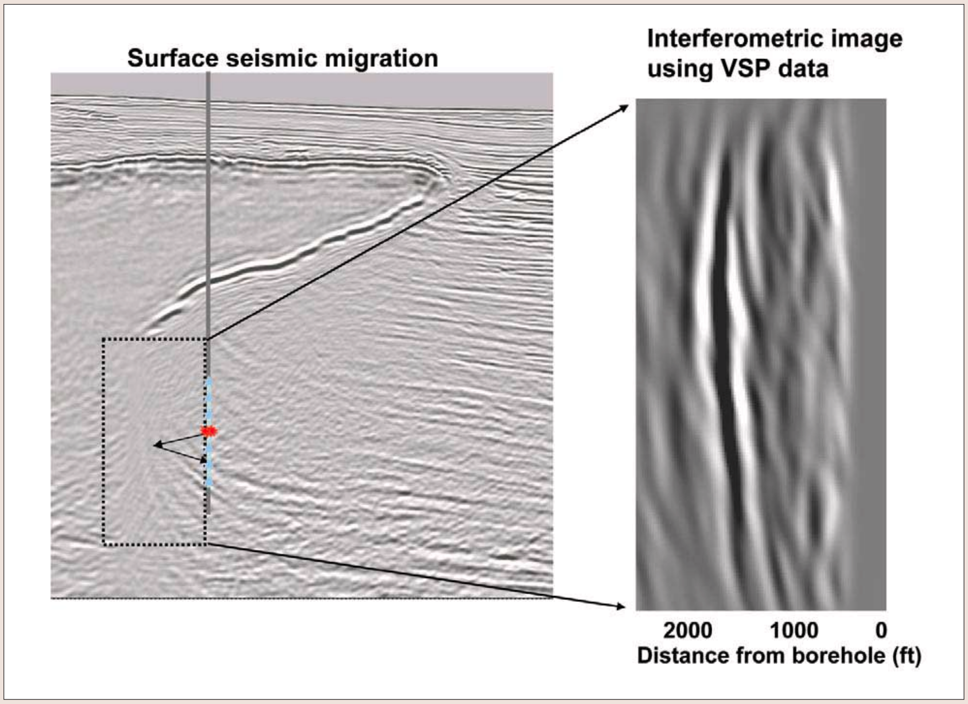


Figure 9. *Interferometric image using walkaway VSP data. Interferometry is used to create virtual sources at the receiver array creating a series of common source gathers, one for every receiver. These data are then used to directly image the salt flank with no knowledge of the overburden or salt structure needed.*

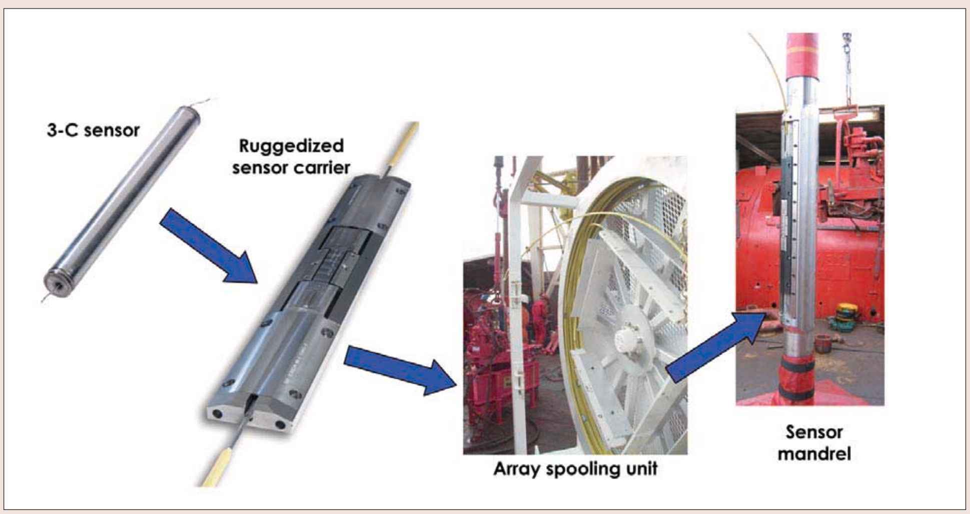


Figure 10. *Instrumentation of a well using fiber-optic seismic sensors. A sensor package contains a 3-C accelerometer, a sensor carrier contains the fiber-optic sensor package, which then is placed into a mandrel that places the sensor package between tubing stands. The seismic sensors are isolated from the tubing using a small spring-loaded pad that couples through the casing to the surrounding formation.*

new data set with downhole "virtual sources" located at each geophone position. The advantage of this technique is that knowledge of the overburden is not required; imaging is accomplished using only the local velocity field below the geophone array. In the case of a vertical well near a salt flank, we end up with a single well imaging geometry with downhole sources and receivers and directly acquire specular reflections from the salt flank. Here the only velocity model we need to concern ourselves with is the velocity of the sediments between the receiver array and the salt flank; no knowledge of the overburden or salt structure is required. The local velocity field can be initially estimated using the velocity as recorded along the receiver array in the borehole. An example is shown in Figure 9. Interferometry is used to create virtual sources at the receiver array, creating a series of common source gathers, one for every receiver. These data are then used to directly image the salt flank using WEM PSDM. As seen on the image, we have a direct image of the salt flank showing it to be about 1500 ft from the borehole.

Reservoir monitoring using permanent in-well seismic. Recently, fiber-optic technology has been developed for reservoir monitoring using permanent in-well seismic (Bostick, 2000; Hornby et al., 2005b; Keul et al., 2005). For 4D reservoir monitoring new challenges and opportunities arise beyond static VSP imaging. One key question is repeatability. A recent paper looked at this question for time-lapse VSP and concluded that a fixed downhole geophone tool can acquire seismic data with an excellent degree of repeatability (Landrø et al., 2001). Initial trials of the fiber-optic technology demonstrated that the technology works and that signals of comparable fidelity to standard electric geophones could be obtained using fiber-optic-based sensors deployed on tubing. Final design, as developed by Weatherford, for tubing-conveyed installation in production wells has a mandrel design incorporating an active pad used for isolating the sensors from tubing resonances (Figure 10). Another question is this—can we acquire borehole seismic data during production of a well? Results of a field test to examine the effect of production noise on VSP data with permanent in-well fiber-optic sensors are shown in Figure 11 (Knudsen et al., 2006). With single phase (water) flow, excellent-quality seismic data were acquired, and with multiphase (water/air) flow, good-quality data were acquired, with more noise on the radial (x,y) sensors. Going forward, we see permanent instrumentation of wells with seismic sensors a strong player for reservoir monitoring where seismic illumination (e.g., subsalt) or signal to noise for surface 4D is a problem. In this case one might deploy permanent seismic sensors in multiple wells to give a larger, reservoir-scale coverage. In addition, for permanent VSP sensors, imaging using multiples can add substantial value to 4D monitoring using primary arrivals. Here, in addition to imaging potentially to a larger, seismic-scale extent from the borehole, imaging with multiples allows one to image and monitor the overburden all the way to the surface.

Conclusions. For VSP, two areas of interest beyond the traditional time-to-depth application is 3D VSP imaging and

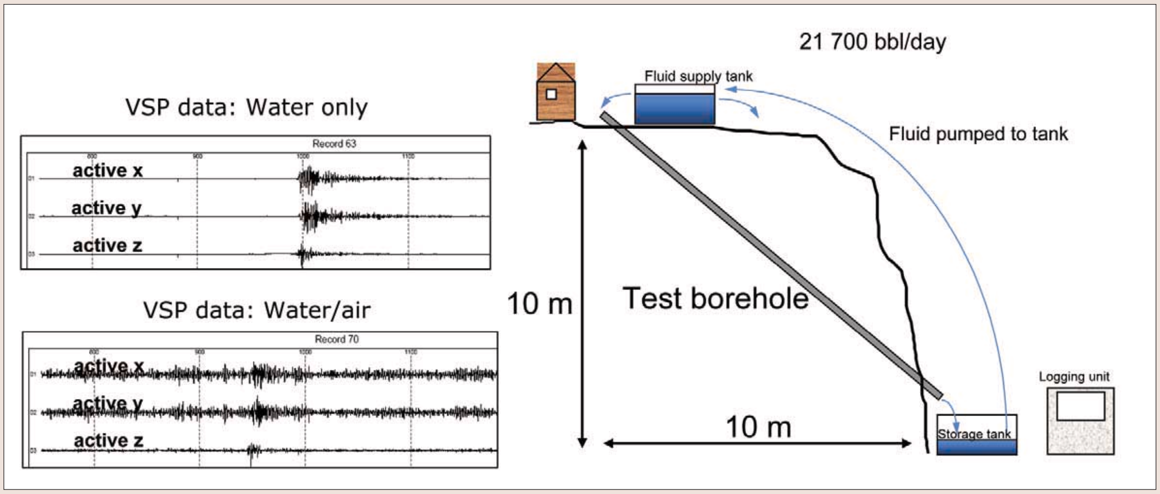


Figure 11. Field test to examine effect of production noise on VSP data with permanent in-well fiber-optic sensors. With single phase (water) flow, excellent-quality seismic data were acquired, and with multiphase (water/air) flow, good-quality data were acquired, with more noise on the radial (x,y) sensors.

reservoir monitoring using permanent borehole seismic sensors. For 3D VSP imaging, use of 3D FDM modeling as a planning and risk management tool for 3D VSP surveys is a new development. This tool should be used before every VSP imaging survey to determine if the potential prize meets our expectations and what survey design is necessary to achieve that prize. Below complicated salt, for example, a 2D survey (walkaway VSP) may not adequately image due to the breakdown of the 2D assumption—FDM modeling can test that concept. 3D VSP imaging examples were shown for both extra salt and subsalt cases for wells in the deepwater Gulf of Mexico. In both cases the 3D VSP clearly added value. The extra salt case showed images of subseismic scale structure and reduced risk on a sidetrack well planned to drill a key reservoir section. The subsalt case demonstrated a clear example of imaging using 3D VSP where the surface seismic is blind. In the subsalt case, three boreholes were drilled due to an unexpected fault of 1500 ft throw that was not seen on the surface seismic results. Images of both the reservoir and the fault were seen on the 3D VSP. Potentially we could have saved two sidetrack wells if the 3D VSP survey was acquired before the first well was drilled. On new imaging techniques to take advantage of the special geometry of the VSP survey, we looked at imaging with multiples and salt flank imaging using interferometry. Imaging with multiples can bring additional fold and coverage for VSP imaging not seen by the primaries. Results showed a spectacular image of a 40 000-ft-long section in one case and high-quality images of subsalt bedding in another case. The beauty of this technique is that one can image using data we have already acquired—we simply look later in time for the multiples. Obviously one must also acquire long enough records to capture the multiples for deepwater Gulf of Mexico, acquisition of 12 s records is a good starting point which can be fine-tuned with ray-tracing analysis. In the case of salt flank imaging, interferometry allowed us to redatum the surface sources to the geophone array, resulting in a single well imaging geometry, with downhole sources and receivers. In this case direct imaging of the salt flank was accomplished using prestack depth migration techniques with no knowledge of the overburden or salt geometry required. For reservoir monitoring using permanent in-well seismic sensors, we detailed a production-well-ready assembly for permanent emplacement of an array of 3-C seismic sensors. Initial field trials demonstrated that we can acquire equivalent data to wireline deployed tools and established the current system for conveying and coupling the seismic sensors to the surrounding formation. In addition, a field trial with flow rates of 27 200 b/d and both single- and mixed-phase flow showed excellent-quality data for these high flow rates, giving us promise for acquiring permanent VSP data while a well is producing.

Suggested reading. "Virtual source: new method for imaging and 4D below complex overburden" by Bakulin and Calvert (SEG 2004 *Expanded Abstracts*). "Field experimental results of three-component fiber-optic seismic sensors" by Bostick (SEG 2000 *Expanded Abstracts*). "VSP salt flank imaging through wavefield continuation" by Brandsberg-Dahl et al. (EAGE 2003 *Extended Abstracts*). "Synthesis of a layered medium from its acoustic transmission response" by Claerbout (GEOPHYSICS, 1968). "Migration methods for passive seismic data" by Draganov et al. (SEG 2004 *Expanded Abstracts*). "3D VSP in the deep water Gulf of Mexico fills in subsalt shadow zone" by Hornby et al. (EAGE 2004 *Extended Abstracts*). "3D VSP used to image near complex salt structure in the deep water GOM" by Hornby et al. (EAGE 2005a *Extended Abstracts*). "Field test of a permanent in-well fiber-optic seismic system" by Hornby et al. (GEOPHYSICS, 2005b). "Migration of multiples" by Jiang et al. (*TLE*, 2005). "Using a fiber-optic seismic array for well monitoring" by Keul et al. (*TLE*, 2005). "Flow-induced noise in fiber-optic 3-C seismic sensors for permanent tubing-conveyed installations" by Knudsen et al. (EAGE 2006 *Extended Abstracts*). "Mapping reservoir pressure and saturation changes using seismic methods—possibilities and limitations" by Landrø et al. (*First Break*, 2001). "High-resolution 3D seismic imaging using data from large downhole seismic arrays" by Paulsson et al. (*First Break*, 2004). "Considerations for high-resolution VSP imaging" by Payne et al. (*TLE*, 1994). "Largest 3D VSP in the deep water of the Gulf of Mexico to provide improved imaging in the Thunder Horse South field" by Ray et al. (SEG 2003 *Expanded Abstracts*). "Acquisition of 2D walkaway VSP data to improve imaging of Thunder Horse North Field, Gulf of Mexico" by Ray et al. (*TLE*, 2005). "Interferometric/daylight seismic imaging" by Schuster et al. (*Geophysical Journal International*, 2004). "Effects of changing the receiver array settings on VSP images" by Van Gestel et al. (SEG 2003 *Expanded Abstracts*). "Retrieving the Green's function by cross-correlation: a comparison of approaches" by Wapenaar et al. (*Journal of the Acoustical Society of America*, 2005).
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