Baseline processing of a dual-well 3D VSP: A case study from monitoring steam-assisted gravity drainage in the Canadian Oil Sands
Stefan Dümmong*, Richard Tøndel, and Andrew Barrett, Statoil; Allan Campbell and Les Nutt, WesternGeco and Robert Godfrey, Schlumberger

Summary
After installing permanent 3C geophones in two vertical observation wells for reservoir monitoring, a dual-well 3D Vertical Seismic Profile baseline survey was acquired as a foundation for observation of future production effects from steam-assisted gravity drainage. Data processing was challenged by turning waves arriving as first arrivals and migrating this unusual 3D Vertical Seismic Profile geometry setup. After understanding and overcoming these challenges, the data provided a high-resolution image around and between the two observation wells and an updated subsurface model in terms of velocity and anisotropy parameters. The 3D Vertical Seismic Profile image shows a higher resolution compared to the surface seismic data, allowing a more detailed interpretation of the subsurface. Additionally, the data show that the imaged area will cover the expected production effects of four steam-assisted gravity drainage injector/producer wells in the vicinity of the two observation wells which will be investigated by future time-lapse acquisitions.

Introduction
A joint research project between Statoil and Schlumberger is focusing on permanent crosswell geophysical methods for reservoir monitoring during steam-assisted gravity drainage (SAGD). In 2009, a feasibility study indicated detectable differences in seismic and electrical reservoir properties based on expected changes in temperature and fluid saturation during oil production. Based on these results, several geophysical reservoir monitoring methods were evaluated. These included crosswell seismic measurements, Electrical Resistivity Tomography (ERT) and 3D Vertical Seismic Profiling (VSP). The modeling study was followed by installing a permanent crosswell monitoring system at Statoil’s Leismer Demonstration Area in Alberta, Canada, in 2010 (Tøndel et al., 2011). After the system was successfully installed and tested, baseline datasets were acquired through an established data link, allowing for remote monitoring throughout the calendar year. ERT datasets can be acquired without personnel on site, while conventional borehole seismic acquisitions require a moving source on the surface or a crosswell seismic source and receiver array deployed on wireline. During 2012, several time-lapse studies will be executed to reveal how these different methods are able to monitor the reservoir during SAGD.

One of the selected methods to monitor the reservoir during steam injection is time-lapse 3D VSP which allows for high-resolution imaging as well as seismic parameter estimations (e.g., anisotropy). In contrast with conventional 3D VSPs in one well, the setting with two parallel vertical wells, separated by 150 m (Figure 1), maximizes the imaged area between and around the wells. Four injector/producer well pairs are displayed in Figure 1. It should be possible to detect production effects from these wells with the planned survey geometry.

Figure 1: Geometry of the dual-well 3D VSP acquisition at the observation wells (grey bullets represent surface source positions; green/red bullets represent downhole receiver positions). The two vertical observation wells and four injector/producer wells are displayed over a Top Devonian map.

The baseline 3D VSP survey was acquired in March 2011, only weeks after steam circulation started.

Pre-survey planning and data acquisition
To acquire a baseline 3D VSP dataset, thorough pre-survey planning was executed in 2010. Dual 3D VSPs are rarely acquired (Sanchez and Schinelli (2007) described a dual 3D VSP acquisition onshore Brazil), thus special attention had to be given to the survey design. One of the challenging topics during survey design was to optimize the acquisition for both wells simultaneously. Because both observation wells are equipped with 32 three-component (3C) geophones that were permanently cemented in the well

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annulus, the survey planning objective was to choose the optimal source placement on the surface.

To achieve optimal source placement, detailed ray based pre-survey modeling was executed. It was decided that a 1 x 1 km checkerboard pattern on the surface would be a good compromise because existing cut-lines through the terrain could be used while still achieving the desired processing products (i.e., high-resolution images around the wellbores).

Figure 2 shows a display of the source locations. The 21 N-S lines were planned with a 5 m source point interval, while the individual lines were separated by approximately 50 m. In addition to the main acquisition setup, two extended lines were planned in N-S and E-W directions. These two lines covered a length of approximately 2 km each, as can be seen in Figure 2. The data were acquired using mini-vibrators allowing for efficient acquisition and minimal environmental disturbance.

A 27 s source sweep was chosen to cover a frequency band of 8-180 Hz, while the added listening time was 3 s. Approximately 3400 source points were acquired during the baseline data acquisition which lasted approximately 55 hours. As can be seen from Figure 2, a creek crossing the central parts of the area influenced the source point distribution north of the observation wells.

Data processing

Due to the fact that the downhole recording unit and the source controller recorded data in two different systems, special care had to be taken to set up and QC the data geometry. Source location and receiver data were combined by correlating the GPS time stamps from the two separate systems.

After setting up the geometry, a thorough QC program was run to verify both geometry and data quality. This included data editing, filtering, initial traveltime picking, and static corrections. One of the QC criteria for geometry setup was the assumption that picked traveltimes for the direct downgoing waves should in general increase smoothly with offset for every receiver. An example of this behavior can be found in Figure 3, where we see smoothly increasing traveltimes away from the boreholes.

Figure 3: Direct downgoing arrival traveltimes picked for geophone number 9 in the east observation well. The traveltime curve varies relatively smoothly with offsets. However, hand picking was necessary on far-offset traces due to turning waves affecting the pick accuracy.

Imperfections in the near-surface static model were observed during traveltime QC. As a result, unaccounted irregularities in the residual statics occurred. To minimize these effects, a velocity model was generated from near-offset shot positions (i.e., Zero Offset VSPs) and updated traveltimes were calculated. The residuals between the calculated and the picked traveltimes were then minimized by an inversion scheme and the data were corrected for the residual static. Following this correction, the traveltimes varied smoothly from near- to far-offsets.
Baseline processing of a dual-well 3D VSP

A complicating factor during the QC process was that turning waves started to appear as first arrivals at offsets exceeding approximately 400 m. Thus, the applied fast automated traveltime picking algorithm that detects the first motion on the 3C Hilbert envelope was hampered and pick refinements by hand were necessary to complete this QC process.

Detailed inspections of the data showed that some of the shallowest receivers on the west well were not providing sufficiently high quality data and that a few traces showed a relatively low signal-to-noise ratio (S/N). Further, we noticed that only limited shear wave energy was arriving on the horizontal components. Generally, we concluded that high-quality data were acquired and that they were very well suited for high-resolution imaging. However, due to the data restrictions mentioned above, baseline data processing focused mainly on the vertical components of the data.

After the initial pre-processing steps, wavefield separation was applied to the data. Assuming a horizontal layering and limited lateral velocity variations in the subsurface, median filtering for VSP wavefield separation (Hardage, 2000) worked well. More general methods accounting for the complete wavefield such as parametric wavefield decompositions (e.g., Leaney, 2002) were not applied because the shear content in the data was limited and a low S/N ratio at greater offsets could affect the application. Satisfying wavefield separation results for the near-offset traces can be seen in Figure 4. Results for far-offset traces were, however, hampered by the strong influence from turning waves, as indicated in Figure 5.

Before commencing the imaging part of the data processing, we decided to calibrate the surface seismic velocity model with the obtained VSP traveltimes through a tomographic update. The direct downgoing traveltime residuals for offsets up to 400 m were seen to be constrained by the inversion algorithm (Cao et al., 2000) to +/- 10 ms, as shown in Figure 6. Longer offsets still showed significant residuals and were subsequently omitted from the imaging attempts. During the model calibration, it was decided to simultaneously update the velocity and the VTI anisotropy parameters ε and δ determined by the surface seismic processing. Due to the fact that only downgoing direct arrivals, covering a cone shaped area around the boreholes, are incorporated in this process, the inversion might become unstable. However, in this case the algorithm delivered stable results for velocity and anisotropy parameters, but no significant changes could be observed.

Figure 4: Near-offset shot wavefield separation by median filtering. From left to right the complete wavefield is separated into downgoing, upgoing, and enhanced upgoing events.

Figure 5: Far-offset shot wavefield separation by median filtering. From left to right the complete wavefield is separated into downgoing, upgoing, and enhanced upgoing events. The separation is does not work due to the presence of turning waves at deeper receivers.

Figure 6: Direct downgoing traveltime residuals (measured vs. modeled) after model calibration. Offsets shorter than 400 m can be well constrained, whereas longer offset are difficult to invert.

Migrating densely spaced data sets requires an extremely rigorous algorithm. The algorithm must handle dense lateral sampling (5 m source location sampling) as well as an unusual receiver distribution, represented by two vertical wells. Here a Generalized Radon Transform (GRT)
Baseline processing of a dual-well 3D VSP

Migration algorithm (Miller et al., 1987) was applied. The migration images were generated on a 5 x 5 m grid with a 15° aperture around the vertical axis. After data migration, Common Image Gathers (CIGs) were used to evaluate the success of the migration. Because data from both wells were migrated simultaneously, every CIG consisted of a maximum of 64 traces. Simultaneous data migration from both wells can lead to unusually shaped CIGs, where traces with events arriving early and later alternate (Figure 7). As can be seen in Figures 7 and 8, all events in the displayed CIGs are relatively flat, indicating that the selected model provides satisfying results.

Before evaluating the final migration stacks, the inelastic attenuation factor Q (Ziolkowski and Fokkema, 1986) was determined from a near-offset shot location. The attenuation factor was determined by the spectral ratio approach described by Hauge (1981). This was done to apply an inverse Q filter to the stacked volumes that would enhance the final data resolution (Amundsen and Mittet, 1994).

Results

Figure 9 shows the final migration results displayed with the surface seismic data in the background. Although no well calibration has been performed so far, a good match between surface seismic data and VSP images can be observed. Improved spatial and time resolution can be seen in the target area just above the horizontal injector/producer well pairs of the 3D VSP image compared to the conventional surface seismic data.

Conclusions and Outlook

With the underlying results we can demonstrate that the processed dual-well 3D VSP provides higher lateral and time resolution than conventional surface seismic data. However, a baseline survey cannot provide SAGD production effects alone. In early 2012, the first time-lapse dual-well 3D VSP was acquired and is currently being processed. After processing, the dataset will be interpreted and analyzed for time-lapse effects that can be linked to the ongoing SAGD process around the two observation wells. This will be done by means of conventional image comparisons (e.g. Couëslan et al., 2006), traveltme differences, as well as seismic parameter comparisons. Possible VSP derived parameters to be compared could be the P-wave azimuthal anisotropy (Leaney et al., 1999) which can be linked to predefined factures introduced by the steam injection process.

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