



What We Learned From A Horizontal 3D VSP Using Fiber-Optic DAS Technology

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Summary

A 3D Vertical Seismic Profile (VSP) was acquired in a horizontal producing well of a heavy oil field in the Athabasca Oil Sands in 2014. The experiment was part of a research project to determine the applicability of Distributed Acoustic Sensing (DAS) technology in production logging and monitoring. Processing and interpretation of this VSP face many unique challenges, which are mainly due to the horizontal geometry of the well, complications of DAS technology and imaging difficulties of the zone of interest. Beside these challenges, the well was intentionally shut in only for a short period, and the pump was working at different speeds during the acquisition, resulting in a low signal to noise ratio. Travel time tomography of the VSP's first arrivals was used to build a 3D p-wave velocity model, but the model needed help from the surface seismic velocities, which were used as a starting point. The Reverse Time Migration (RTM) method was then implemented to construct the seismic image. After a series of enhancements, the velocity model could delineate the approximate extent of different parts of the reservoir, which were affected by operations like: the steam chamber, the top of the heated oil and virgin reservoir. On the other hand, the seismic image itself was still chaotic and obscure. Further analyses using RTM on a single receiver revealed the cause. In order to image the features, which sit above the receiver level, we have to rely on the imaging of the multiples instead of primary reflections. Relying on the multiples requires a sharp, high contrast velocity model, which, in return, generates reflected wavefronts in the RTM process. These wavefronts cover the section with strong artifacts, which obscure the image.

A review of these challenges and their corresponding solutions are presented in this paper.

Introduction

The Steam Assisted Gravity Drainage (SAGD) method utilizes steam injection to heat the cold bitumen in the reservoir and reduce its viscosity promoting bitumen flow. The mobile heated bitumen then drains into the producing well (Butler 1998). However, heterogeneity of the reservoir, and the presence of shale and water saturated layers, can complicate the process and reduce its efficiency.

Large acoustic impedance contrast between steam saturated zones and bitumen and hot oil or water saturated rocks is the key factor that enables seismic interpreters to monitor the reservoir with seismic methods (Bianco et al. 2008). Surface seismic monitoring of heavy oil production has proved to be efficient, but it requires at least two seismic surveys at two different times (Chopra et al. 2010), which adds a 4th dimension (time) to the 3D seismic. Depending on the amount of production, the timespan of 4D seismic ranges from a couple of months to a decade or even more. For 4D, the seismic surveys need to be as identical as possible to make the comparison reliable and minimize the calibration errors. On the other hand, the 4D result, even at its best, only provides two largely-spaced images and it does not show incremental changes through time, which are crucial in production planning and management. If the costs and uncertainties associated with 4D seismic decrease, then the frequency of 4D seismic can increase, providing a better understanding of reservoir fluid flow. A better understanding of fluid flow allows engineers to optimize well parameters to enhance bitumen production.

VSP is a well-known method in borehole geophysics (DiSiena et al. 1984). Depending on the design, it provides even more opportunities than surface seismic can offer (e.g. higher resolution and better depth

control, with the exception of spatial coverage). DAS cables are products of a new developing technology, which uses fiber optic cables as strain detectors and works based on Rayleigh scattering of laser pulses. In a DAS VSP operation, a fiber-optic cable can be permanently installed inside the wellbore. Often, the DAS cable will be there for engineering purposes already. If the wellbore environment is quieter than a seismic shot, then a VSP can be acquired without interrupting production. In a DAS cable, all channels are live simultaneously. Consequently, one shot results in a full VSP record of the entire well path. Theoretically, this implies a significant improvement in VSP operations, including time, cost and repeatability (Mateeva et al. 2014; Wu et al. 2015). An appropriate 3D DAS VSP in a horizontal well may also provide sufficient spatial coverage to image the steam chamber over that well. Using DAS VSPs in horizontal wells has the promise to replace 4D surface seismic with 4D VSPs, which can be acquired more often than conventional 4Ds, using DAS cables already deployed in the wells for engineering purposes.

Theory and/or Method

One of the outputs of a VSP operation is time-depth relationship or velocity information. A 3D velocity model in depth domain can be built by travel time tomography of first arrivals from the VSP. However, the amplitude response of the straight DAS cable that was used in this operation is directionally dependent. A disturbance parallel to the cable is fully recorded, and as the angle of incidence increases, the amplitude response gradually decreases until it approaches zero at 90 degrees to the cable (broadside incidence). This problem results in weak amplitude traces of first arrivals from shots near-broadside to the cable. Correct picking of these first arrivals is essential in travel time tomography, but difficult for these near-broadside traces.

Horizontal well trajectories are more uncertain than vertical well trajectories. Therefore, the position of the DAS cable, and, therefore, the VSP receiver positions, are uncertain. This uncertainty makes the tomography and imaging more challenging.

The accuracy of the final velocity model at a certain grid cell is dependent on the density of the rays which pass through that cell. Since the near-surface trace density is low, near surface velocity uncertainty is high and this uncertainty may adversely affect the quality of a depth migration process. However, it should be mentioned that travel-time tomography, like other inversion techniques, generates a non-unique answer.

Having worked through the difficulties of building a velocity model, now that model can be used for RTM imaging. RTM is a pre-stack depth imaging method that is a two-way wavefield extrapolation technique. RTM uses the following principles (Robein 2010):

- 1- To emulate the downgoing wavefield from the source (starting time=0)
- 2- To reconstruct the full upgoing field back in time and everywhere in the subsurface (starting time= recorded time of the event)
- 3- To apply the imaging condition: to find reflectors where and when the two wavefields are coincident in time

The standard RTM algorithm is designed to image the primaries. However, in this case, there are no primary reflections from the reservoir because the reservoir is above the receiver line depth level, which is in the producer well of a SAGD well pair near the bottom of the reservoir. Consequently, the steam chamber and its boundaries can not be imaged using the primaries alone.

Unlike VSPs from vertical wells, in which a dip attribute can be used to separate downgoing waves from upgoing waves, in this experiment no wavefield separation can be performed because all the waves passing through the reservoir to the VSP receivers are downgoing.

These are among the challenges that make processing and interpretation of a DAS VSP from a horizontal well more difficult. However, the solutions developed to address some of these challenges will be discussed in the presentation.

Conclusions

The quality of the final seismic image is a function of many effective variables from the beginning of the acquisition to the final steps of processing. A horizontal geometry, new technology and other imaging

difficulties posed many challenges in the assessment of the DAS-VSP technique. Several methodologies were developed as part of this project to address some of these issues. Some are practical, some need further development and some need improved economics.

The velocity model derived from raypath tomography shows agreement with available data and can be used to interpret some interesting features, like the top of the heated oil at the base of the steam chamber, the top of the steam chamber and other lithology surfaces.

The seismic image is difficult to obtain from this geometry, due to the unique geology of oil sands reservoirs, and, except for reflections from a sharp lithology interface at the top of the Devonian, it does not provide much useful information. The RTM image of a single receiver shows that the section is fully covered with strong artifacts, due to sharp velocity contrasts in the model between the McMurray sands and the Devonian carbonates. One way to suppress these artifacts is to estimate the slope of downgoing and upgoing wavefield and compare them at each imaging point. If they are equal and the standard imaging condition is satisfied, then a scaled reflection amplitude could be assigned to that grid cell.

Based on the difficulties encountered during this study, the applicability of the DAS VSP method in horizontal wells, as a replacement for surface seismic monitoring, is still an open question. This DAS-VSP study did provide some useful data, specifically the velocity model from the tomography, which shows reasonable agreement with other information about the steam chamber at the time of the VSP acquisition. The velocity model could be obtained from data that was acquired while the well was producing from the fiber-optic cable in the horizontal portion of the SAGD producer well in which the fiber optic cable was placed. Being able to continue production while acquiring a VSP is extremely important for the VSP economics. VSP data from the build section of the well, acquired during a short shut-in period, or VSP data from a nearby vertical well can substantially improve the processing and VSP results.

Further developments of the methods discussed here are warranted by the results achieved in this project.

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